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USE OF GENERALIZED NETWORK FLOW PROGRAMMING IN SOLVING THE OPTIMAL POWER FLOW PROBLEM

by

ROY EUGENE RICE, B.S., M.S.

DISSERTATION

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

DOCTOR OF PHILOSOPHY

THE UNIVERSITY OF TEXAS AT AUSTIN

MAY 1986

This dedication . . .

To my wife, Deborah,

who asked for so little but sacrificed so much.

To my parents, Bill and Lois,

who provided guidance, wisdom, and a loving touch.

To my daughters, Nicole and Tamitha,

who gave me priorities with their smiles and needs.

To the memory of Miss Carolyn Mann,

who never quit believing in me.

USE OF GENERALIZED NETWORK FLOW PROGRAMMING

IN SOLVING THE OPTIMAL POWER FLOW PROBLEM

Publication No. ____

Roy Eugene Rice, Ph.D.
The University of Texas at Austin, 1986

Supervising Professors: William G. Lesso
W. Mack Grady

Exact solutions to the classical optimal power flow (OPF) problem require complex and computationally intensive computer algorithms. Often, a faster, simpler solution technique which provides reasonable accuracy is more desirable in system control center applications where speed is critical. The purpose of this dissertation is to formulate and develop such a solution technique based upon Generalized Network Flow Programming (GNFP). The resulting algorithm is demonstrated using a five bus power system example, a 39 bus example, and a reduced equivalent network of an actual power system.

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I am extremely grateful to the Air Force for paying the bills and giving me the opportunity to pursue my terminal degree.

Mostly, I humbly thank my parents, my wife, and my children for their love, strength, friendship, and support.

R. E. R.

USE OF GENERALIZED NETWORK FLOW PROGRAMMING

IN SOLVING THE OPTIMAL POWER FLOW PROBLEM

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USE OF GENERALIZED NETWORK FLOW PROGRAMMING IN SOLVING THE OPTIMAL POWER FLOW PROBLEM

Exact solutions to the classical optimal power flow (OPF) problem require complex and computationally intensive computer algorithms. Often, a faster, simpler solution technique which provides reasonable accuracy is more desirable in system control center applications where speed is critical. The purpose of this dissertation is to formulate and develop such a solution technique based upon Generalized Network Flow Programming (GNFP). The resulting algorithm is demonstrated using a five bus power system example, a 39 bus example, and a reduced equivalent network of an actual power system.

Roy Eugene Rice, Captain, USAF, 1986, 130 pages, Ph.D., University of Texas at Austin.

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CHAPTER I

INTRODUCTION

In 1984, 26.7 billion dollars was spent in the generation of electrical power in this country. This produced an estimated 1.4 trillion megawatt-hours (MWH) that was demanded by private citizens and businesses in the U.S. Even as little as a 1% reduction in the dollars spent to produce enough power to meet these demands would represent a substantial saving.

Since the early 1920's, power system engineers have continually sought methods to more efficiently allocate the generation resources to meet growing demands. Each generation unit has a cost function associated with it. There are also upper and lower limits to the amounts of power each unit can produce. These limits are based on engineering principles, political decisions, maintenance scheduling, and a host of other factors. All of these characteristics make this efficient allocation of power generating resources a classic optimization problem. And the potential benefits from this

optimization are enticing enough to spur research into another solution technique - one based on Generalized Network Flow Programming (GNFP).

1.1. The Power System

A power system is a system of generators connected to diverse load points by transmission lines. These transmission lines terminate at busses. At these busses, there can be a generator (source of electrical power), a load (demand point for electrical power), both generation and load, or neither (simply a connection). The power that is generated has two components: a real part and an imaginary part. The real part is called Real Power (measured in watts or megawatts, MW) and the imaginary part is called Reactive Power (measured in megavars, MVar). Even though Reactive Power is imaginary, mathematically, it has tremendous effect on voltages and power system operation. Therefore, power is represented as a complex number $S_i = P_i + jQ_i$, where S_i is the complex power at bus i and is composed of the real power at bus i, P_i, and the reactive power at bus

i, Q_i. Power (S), voltage (V), and current (I) are all complex variables. Complex power is defined as

$$S = VI^*,$$

where I^* is the conjugate of complex current. This means that if I has a real component, x, and an imaginary component, y, I is expressed as $x+jy$. I^*, then, is $x-jy$.

All materials offer some resistance to current flow. Materials offering very low resistance are classed as conductors; materials offering very high resistance are classed as insulators. Two characteristics of transmission lines are impedance and admittance. Impedance, z_{ij}, is the measure of the circuit hindrance to current flow from bus i to bus j. It is a complex number. Admittance, y_{ij}, is a measure of the ease with which current flows down a line from bus i to bus j and is the reciprocal of impedance. Admittance is also a complex number. As power (real and reactive) travels down a line from one bus to another, some is lost.

As stated before, the connection points for lines are called busses. At any one bus, there are four quantities, of which, two are

known and two are unknown. They are P, Q, V (voltage magnitude), and δ (voltage phase angle). Either P and V can be controlled or P and Q can be controlled. When two of these variables are specified or controlled, the others are called state variables since they depend on the state of the other two. Most busses fall into one of two categories - a P-V bus, where the real power (generated or load) and the voltage magnitude are specified and controlled, and second, a P-Q bus, there the real and reactive power (generated or load) are specified and controlled. One generator bus is unique and is called the swing bus. Its selection is arbitrary; but, once it is chosen as swing, its voltage magnitude and phase angle are specified and the voltage of the remaining busses are calculated and specified referenced to it. The power system also contains capacitors and transformers. These P-V busses, P-Q busses, swing busses and transformers will be discussed in later chapters.

In this system, there are several variables. Some are known and some are unknown. Some are control variables and some are state variables. Certain parameters of the system are known. For instance, the admittance, y_{ij}, of each line between busses is known. Also known

is the total line charging admittance, y'_{ij}, of each transmission line, which is a measure of the shunt capacitance of the line. The line acts as a source of reactive power.

Conservation of power, which stems from Kirchoff's Laws, must be maintained at each bus. It applies to both real and reactive power and states that power in must equal power out.

Power flow in - Power flow out + Power generated - Power load = 0

These two equations (one for real power and one for reactive power at each bus) make up what is called the Power Mismatch Equations. They will be developed more rigorously later in this dissertation.

A cornerstone of power systems study is the Load Flow or Power Flow problem. Basically, the objective of this problem is to determine the voltage profile and line power flows for a given network with generator and load schedule. This problem will be described more fully in the next chapter in the historical perspective section. The solution must satisfy functional constraints and functional inequalities. These include physical constraints on the reactive power, Q, at some busses; that is, Q may not be allowed beyond some lower and upper bounds. Also, there may be imposed numerical bounds

on the voltage, V, at some busses. There are also limits on the amount of P generated at a bus or the amount of real power allowed to flow on a line due to thermal heating. Therefore, the mismatch equations and several other constraints and restrictions must be satisfied.

1.2. Problem Description

The previous discussion leads to the problem that this research will solve - the Optimal Power Flow (OPF) problem. The objective is to minimize the total power generation cost where each generator has a cost function in terms of real power generated associated with it. The decision variables are the amounts of real power produced at each generator. This minimization must be performed subject to the constraints embodied in the power mismatch equations and some of the constraints and restrictions limiting other variables. A more formal problem statement would be:

Given a set of generators and load points connected by a set of transmission lines, capacitors and transformers, the problem is to minimize the total power generation cost by choosing the amount of real power to produce at each generator, subject to the real and reactive power mismatch equation constraints (which include the power demands at the busses) and the minimum and maximum allowable values on

1. Power generation at each bus
2. Voltages at specified busses
3. Transformer tap values at specified transformers
4. Power flow on lines

Many techniques to solve the OPF are available in the literature. Some of these methods are discussed in the next chapter. Most of these are derivatives of the Newton Method. All have advantages and disadvantages. Primarily, they are difficult to define and understand, and they are time consuming to implement and/or solve.

The purpose of this research effort is to develop another method to solve the OPF problem which avoids most of the complications of nonlinear solution techniques. This proposed method is based upon Generalized Network Flow Programming [1].

CHAPTER II

THE CLASSICAL OPTIMAL POWER FLOW PROBLEM

2.1. Classic Approaches to Generation Cost Minimization

In the early 1920's, this entire area of study was referred to as Optimal Dispatch or Economic Dispatch. The attempt was to minimize F, the energy requirements, in terms of BTU/HR or $/HR. Engineers were concerned with this economic generation allocation, or how to optimally divide the load among the available generators. As discussed by H. H. Happ [2], the two most widely used techniques, prior to 1930, were

1) "the basic load method", where the most efficient generator plant is scheduled to produce at its maximum capability, then the next most efficient generator plant is scheduled to produce at its capacity, and so on,

2) "best point loading", where generator plants are successively scheduled to generate up to their lowest heat rate point

starting with the most efficient plant and proceeding down to the least efficient plant.

In 1930, it was accepted that the incremental method produced the most economic results [2]. This method is based on the idea that the production of additional power should be done by the generating unit with the minimum incremental cost. And, by 1932, it was well established that for economic operations the incremental cost of all machines should be equal. This is a fundamental principle applicable still [2]. Referrence [2] shows how Steinberg and Smith [3] formally proved, in 1934, that equal incremental loading in the case of two machines would result in minimizing BTU/HR or $/HR input. This method was rapidly and widely accepted in the power system operation environment. However, it had some drawbacks. Only the generator powers were considered. The transmission network was neglected. And the calculations for generation allocation for each schedule was very time consuming. Consolidated Edison System Company developed, in 1938, a tool called the Station-Loading slide rule that reduced some of the computational effort [2].

Transmission losses had generally been ignored prior to the

sliderule idea. One of the primary reasons for this was that systems were small and not interconnected. Therefore, transmission lines were relatively short. E. E. George in 1943 made significant contributions with his derivation of his loss formula and its subsequent evaluation [15]. The loss formula was used throughout the 1940's in the construction of average loss charts. But it was recognized that the industry needed an approach to include incremental fuel costs and transmission losses. At this point, economic dispatch was an unconstrained optimization problem. Referrence [2] discusses in detail the independent works by George [15,16], Ward [16,17], Kron, and Kirchmayer and Stagg [18,19, 21]. These works in the following 10 to 15 years, along with the emergence of the digital computer, made great strides and led the industry to the end of the classic era.

2.2. Conventional Power Flow

In the late 1950's, the load flow problem (discussed in Chapter 1) began to appear on new digital computers. To describe the load flow problem, an explanation of the notation must be given. A power system consists of n busses connected by m transmission lines.

A transmission line connects bus i to bus j, where $i \in \{1,2,\ldots,n,\}$ and $j \in \{1,2,\ldots,n\}$. Figure 2.1 shows a system of 39 busses and 46 lines. At the circled busses are the generators. They generate (are a source for) complex power. As stated earlier, power has a real part (Real Power) and an imaginary part (Reactive Power). The real power generated at bus i is denoted P_{gi}. Similarly, Q_{gi} is the reactive power generated at bus i. These generator busses may also require power and are called load busses. The power load at bus i is labeled P_{li} and Q_{li}. The other busses (1 through 29 in Figure 2.1) are either connecting busses (no load/generation) or load busses. At each bus, the net injected real and reactive power is denoted $P_{i,inj}$ and $Q_{i,inj}$. They are calculated as $P_{i,inj} = P_{gi} - P_{li}$ and $Q_{i,inj} = Q_{gi} - Q_{li}$. Each generator has associated with it a cost function. In almost all cases, it is a convex function of P_{gi} and is denoted $C_{gi}(P_{gi})$. Examples of these cost functions appear in Chapters IV and V along with the example problems. V_i is the complex voltage at bus i, and $V_i{*}$ is the conjugate of the complex voltage at bus i.

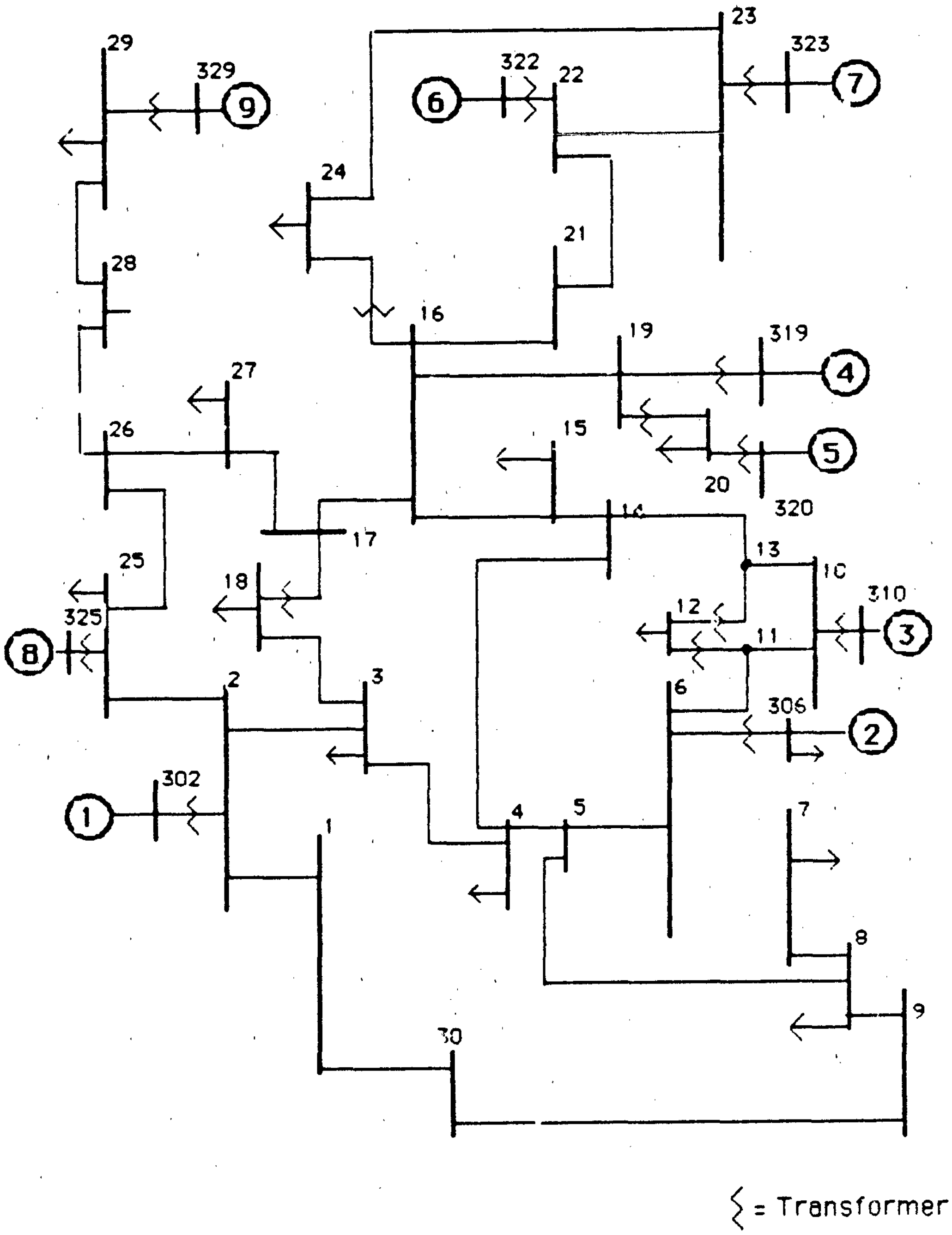


Figure 2.1 39 Bus Example System
New England System

There are properties of the transmission lines that must be explained. Denote y_{ij} as the series admittance of the line between bus i and bus j. Also, let y'_{ij}, be the total line charging admittance on the line from bus i to bus j. This line charging admittance contributes only to the Reactive Power produced by the line.

As mentioned in Chapter I, some variables in the system are known and some are unknown; some are controlled variables and some are state variables. These are

CONTROL VARIABLES (known)	STATE VARIABLES(unknown)
V magnitude at P-V busses	Q at P-V busses
Q at P-Q busses	V at P-Q busses
V at swing bus	Q at swing bus
P at dispatchable generators.	Slack generation/load at the swing bus

The reason there are P-Q and P-V busses (2 variables controlled [known] and 1 variable unknown) is because of the equation for voltage at bus i,

$$V_i = 1/Y_{ii} \left[\frac{P_{i,inj} - jQ_{i,inj}}{V_i^*} - \sum_{\substack{j=1 \\ j \neq i}}^{n} Y_{ij} V_j \right] \qquad (2.1)$$

where Y_{ij}= admittance matrix element i,j (a known parameter). Thus, with two of the variables P, Q, or V specified, the third can be calculated.

The solution of the nonlinear algebraic equations (called the Power Mismatch Equations) describing the power system are based on iterative techniques. The solution must satisfy Kirchoff's laws - in particular, the algebraic sum of all the flows at a bus must equal zero. With P-Q or P-V specified at each bus except the swing, the objective of the Load Flow problem is to find the minimum amount of real power to generate at the swing bus in order to satisfy the Power Mismatch Equations. Mathematically, the formulation of the Load Flow Problem is

$$\text{Minimize } Z = P_{g,swing} \tag{2.2}$$

subject to:

$$\sum_{j=1}^{n} Real\,[\,V_i^*(V_i - V_j)y_{ij} + V_i^* V_i y_{ij}'/2] - P_{i,inj} = 0, \quad i=1,2,\ldots,n \tag{2.3}$$

$$\sum_{j=1}^{n} -Imag[\,V_i^*(V_i - V_j)y_{ij} + V_i^* V_i y_{ij}'/2] - Q_{i,inj} = 0, \quad i=1,2,\ldots,n \tag{2.4}$$

$$\begin{gathered} V_{imin} \le V_i \le V_{imax} \\ P_{imin} \le P_{gi} \le P_{imax} \\ Q_{imin} \le Q_{i,inj} \le Q_{imax} \\ \text{Line min} \le S_{ij} \le \text{Line max} \end{gathered} \tag{2.5}$$

The solution of the load flow problem yields the voltages at all the busses and all other quantities such as current and power can be calculated from these voltages.

2.3 Optimal Power Flow Formulation

Happ [2] describes an "optimal load flow" as

> a load flow in which the fuel costs or some other quantity are minimized, with the ordinary load flow constraints around all buses, and additional constraints such as bus voltage limits recognized. When fuel costs are minimized, the optimal load flow actually serves in the capacity of economic dispatch and determines the real and reactive output of all generators, and

that of other VAR sources, and autotransformer taps to the optimal position.

Each generator has associated with it a cost function. It is, in almost all cases, a convex function (usually quadratic) of P_{gi} and is denoted $C_{gi}(P_{gi})$. Thus, the OPF model is

$$\text{Minimize } Z = \sum_{i=1}^{n} C_{gi}\,(P_{gi}) \tag{2.6}$$

subject to:

$$\sum_{j=1}^{n} \mathit{Real}\,[\,V_i^*(V_i - V_j)y_{ij} + V_i^* V_i y_{ij}'/2] - P_{i,inj} = 0, \quad i=1,2,\ldots,n \tag{2.3}$$

$$\sum_{j=1}^{n} -\mathit{Imag}\,[\,V_i^*(V_i - V_j)y_{ij} + V_i^* V_i y_{ij}'/2] - Q_{i,inj} = 0, \quad i=1,2,\ldots,n \tag{2.4}$$

$$\begin{gathered} V_{imin} \le V_i \le V_{imax} \\ P_{imin} \le P_{gi} \le P_{imax} \\ Q_{imin} \le Q_{i,inj} \le Q_{imax} \\ \text{Line min} \le S_{ij} \le \text{Line max} \end{gathered} \tag{2.5}$$

With the addition of the load flow problem, economic dispatch was transformed from an unconstrained optimization problem to an optimization problem with many constraints.

2.4 Optimal Power Flow Solution Techniques

Happp [2] attributes the beginning of optimal power flow work to Squires [23] and Carpentier in the late fifties and early sixties. Their formulation provides the foundation for much of the work since that time. Carpentier's work led to the general formulation of the Economic Dispatch problem based on the Kuhn-Tucker theorem of Nonlinear Programming. A detailed summary of this treatise appears in referrence [2]. Carpentier arrived at a set of nonlinear equations. To solve them, he used the Gauss-Seidel procedure. But this technique often showed erratic convergence behavior.

Next, came the most significant breakthrough in the power industry in solution techniques of the optimal power flow problem. Hermann W. Dommel and William F. Tinney, in 1968, published their article "Optimal Power Flow Solutions" [4]. Dommel and Tinney had already advanced the state of the art in solution techniques for the load flow problem with their use of Newton's method. In this 1968 paper, they extended this work into the optimal power flow solution. They classified the variables as

1) Unknowns (**x**); voltage at P-Q busses, Q at P-V busses

2) Fixed parameters (**p**); P,Q on P-Q busses, phase angle on the swing bus

3) Control parameters (**u**); voltage magnitude at generator busses, generated real power, P, transformer taps.

Their problem, thus, was

$$\min_{\mathbf{u}} f(\mathbf{x},\mathbf{u}) \qquad (2.7)$$

subject to:

$$g(\mathbf{x},\mathbf{u},\mathbf{p}) = 0 \qquad (2.8)$$

Equation 2.8 is the load flow equations or mismatch constraints. The Lagrangian function is

$$L(\mathbf{x},\mathbf{u},\mathbf{p}) = f(\mathbf{x},\mathbf{u}) + [\lambda]^T [g(\mathbf{x},\mathbf{u},\mathbf{p})] \qquad (2.9)$$

The dimensions are L is 1x1, f is 1x1, $[\lambda]^T$ is 1xm, and g is mx1, where m = [2(#of busses) - #of P-V busses - 1]. Now, the necessary conditions for a minimum are

$$\frac{\partial L}{\partial \mathbf{x}} = \frac{\partial f}{\partial \mathbf{x}} + \left[\frac{\partial g}{\partial \mathbf{x}}\right]^T * \lambda = 0 \qquad (2.10)$$

$$\frac{\partial L}{\partial \mathbf{u}} = \frac{\partial f}{\partial \mathbf{u}} + \left[\frac{\partial g}{\partial \mathbf{u}}\right]^T * \lambda = 0 \qquad (2.11)$$

$$\frac{\partial L}{\partial \lambda} = g(\mathbf{x},\mathbf{u},\mathbf{p}) = 0 \qquad (2.8)$$

The first condition, Equation 2.10, has as one of its terms the transpose of the Jacobian, which is always square. Solving Equation 2.10 for λ yields

$$\lambda = - \left[\left[\frac{\partial g}{\partial \mathbf{x}}\right]^T\right]^{-1} \frac{\partial f}{\partial \mathbf{x}} \qquad (2.12)$$

Dommel and Tinney showed that Equation 2.11 represents the reduced gradient vector $\nabla_{\mathbf{u}} f$

$$\nabla_{\mathbf{u}} f = \frac{\partial f}{\partial \mathbf{u}} + \left[\frac{\partial g}{\partial \mathbf{u}}\right]^T * \lambda \qquad (2.13)$$

The solution process is as follows:

"1) a set of feasible control parameters **u** is assumed, and a load flow by means of Newton's method is obtained," [4]

2) calculate λ by means of Equation 2.12,

3) calculate $\nabla_{\mathbf{u}} f$ by means of Equation 2.13,

4) obtained a correction for **u** by

$$\mathbf{u} = -c \, \nabla_{\mathbf{u}} f.$$

Note the correction factor c. If it is "too small", convergence is prohibitively slow. If it's "too large", oscillations occur. If the control parameters, **u**, are in the form of inequality constraints, they are handled by not allowing them to go beyond their limits. If there are functional inequalities in the **x**'s, an approach such as the penalty function approach must be employed. This is the major drawback to this method - which is the most popular method of solving the optimal power flow problem in the United States. Also note the similarity between the reduced gradient (Equation 2.13) and the first derivative of the objective function in an unconstrained minimization like economic dispatch (Equation 2.7).

Since Dommel and Tinney published their article in 1968, the advancements in the state of the art in optimal power flow solution techniques have primarily been in the areas of solution techniques to nonlinear programming problems and more efficient storage and computational algorithms. Analysts have continually tried to solve

larger problems as the power systems have gotten larger. And with these solution attempts, the analysts have included more detail, such as different types of transformers, different objective functions, and detailed sensitivity analysis.

Stott, Alsac, and Marinho [5] present a general discussion of the more popular methods being used today.

a. Generalized Reduced Gradient (GRG) Approach. This is based on the Dommel-Tinney method. The major departure lies in the treatment of the functional inequalities; or, the upper and lower bounds on V, P, and Q. To obtain an initial feasible solution, penalty functions are used. But, once the process begins, whenever a limit is violated, that quantity enters the set **u** as a control variable, and a former control variable leaves the set **u**. Once an initial feasible solution has been found, the algorithm starts at step (3):

1) solve the load flow problem,

2) find all quantities violating their limits and designate them as a control variable in **u**. By linear sensitivity analysis find a present member of **u** and designate it as a dependent variable in **x** (without violating its limits),

3) obtain new **u** by gradient step similar to Dommel-Tinney,

4) iterate from (1) until converged.

Step (2) is not that well developed at the present. It can be time-consuming and is prone to error. The GRG appears to be more robust and takes fewer iterations than Dommel-Tinney. However, each iteration requires more computations.

b. Pure Constraint Linearization Methods. This family of techniques can be generally described by the following algorithm [5]:

1) solve the load flow problem,

2) linearize the constraints,

3) minimize the objective function subject to these constraints,

4) iterate from (1) until converged.

When the constraints lend themselves to adequate linearization, extremely few iterations are needed. The typical objective function is such that it can usually be expressed as a linear function, a separable-convex function, or a quadratic function. There are

efficient mathematical programming codes available to solve these. A Linear Programming approach can be developed to handle separable piecewise-linear or smoothly convex objective functions. However, they have to be "tailored" to this problem and it must be recognized that the assumptions of linearity make these techniques "approximations" to the nonlinear problem. Linearization also increases the size of the problem by adding variables to indicate the linear segment in use.

Two particular works on power dispatch involve the clever use of minimum cost flow techniques in network flow programming [31,34]. This is a linearization method. Successive applications of the minimum cost flow method in [34] showed improvements over the Minty-Lee Method in [31]. The technique developed in this dissertation is similar to the one in [31,34] in its basic approach. However, with this technique, the transmission losses are handled directly, and there is no need for successive applications of a minimum cost flow algorithm.

c. Active-Power Balance. A power system has an active-power balance that can be shown

$$\Sigma \text{ generations} = \Sigma \text{ loads} + \text{transmission losses}$$

As discussed in referrence [5] , in the formulation and solution of the load flow equations, the generation at the swing bus (P_{gs}) is made to be dependent on the *a priori* unknown network power losses, and thus satisfies the active-power balance. Whenever P_{gs} influences the optimal power flow solution (as a control variable, with an associated cost, or with limits), this balance must be included as a problem constraint. Since the losses are not mildly nonlinear, the acceptability of linearization of the power balance equality depends on the application. In typical economic dispatch or optimal power flow, such linearization is common and usually quite adequate. Again, special coding efforts must be done to include this type of constraint in any specific application.

d. Reduced Methods. Referrence [5] suggests three approaches that are classified as Reduced Methods: the Carpentier method (with a linearized power balance), primal methods which are applied to the linearly constrained, separable-convex objective problem, and a dual approach. The Carpentier method has been

discussed previously. It should be noted that primal approaches are wrought with difficulties such as large numbers of quantities violating their limits.

"A dual approach appears to be more suitable, introducing one 'most-violated' inequality at a time" [5]. Also, in this discussion is the following dual-approach algorithm:

(1) solve the load flow problem for **u**,

(2) linearize the power-balance equation and find an optimal solution for **u** that satisfies this equation and the limits on **u**,

(3) solve the linearized power flow for **x**,

(4) find the most violated inequality and express it as a function of **u** from linear sensitivities,

(5) use a dual separable-convex method to solve the problem:

min f(**u**)
subject to:
- - power balance equation
- - the incoming linear inequality
- - already binding linear inequalities
- - limits on **u**

(6) recycle from (3) until all violations are removed,

(7) iterate from (1) until converged.

Steps (3) through (5) are executed for each of the m functional equalities which become binding during the solution (m is fairly small for most practical problems). This sort of scheme is very fast, especially when the constraints can be accurately approximated by linearization. However, this approach has the same generality limitations as Carpentier's method [5].

e. Pure Penalty Approaches. This is a classical nonlinear programming approach in which the constraints are added onto the objective function as penalties and solved as an unconstrained minimization problem. As stated in [5],

> none of the classical direct methods, such as DFP or conjugate gradients, have appeared to be attractive, due to the dimensionality and/or sparsity considerations. The difficulties introduced by dimensionality and/or sparsity are obvious when considering that even a moderately sized problem would have thousands of constraints and variables and extremely few variables per constraint. Instead, the necessary condition equations have been solved by Newton-type methods.

Here, the problem variables are expressed in terms of the bus voltages so that, in polar analysis, the variable set is $\mathbf{z} = (\mathbf{V}, \boldsymbol{\theta})$ where $\mathbf{V}$ = vector of voltage magnitudes and $\boldsymbol{\theta}$ = vector of phase angles.

Thus, the objective function is

$$f' = f(z) + \sum_i w_i * g_i(z)^2 + \Sigma(\text{outside penalties for violated constraints})$$

where w_i = penalty weighting factor i and the g's are the load flow equations. To solve $\partial f'/\partial z = 0$, it is necessary to iteratively construct and solve for the correction Δz in the equation

$$\partial f'/\partial z = -\partial^2 f'/\partial z^2 * (\Delta z) = -\mathbf{H} * \Delta z \qquad (2.14)$$

where **H** is the Hessian matrix. **H** is symmetric and well-conditioned. "Convergence with a specific set of penalties is usually found to be rapid, in say 2 or 3 iterations"[5]. But, the convergence of the overall problem is often considerably longer. The w_i's must be adjusted to satisfy the load flow equations. This method has to be "tuned" in the process of solving the problem which makes it less attractive. Infeasibility detection is not accomplished and no marginal costs are provided.

f. Sequential Quadratic Programming (SQP). Several years ago the Electric Power Research Institute (EPRI) initiated Project RP 1724-1, in an attempt to develop a comprehensive OPF computer code. Energy Systems Computer Applications (ESCA) was

awarded the contract and, with the consultation of Tinney and others, established SQP as a viable solution technique. In a March, 1983, memorandum from ESCA to EPRI, they describe this SQP approach in response to the ongoing EPRI project RP 1724-1[6]. SQP appears to be a promising method for solving non real time optimal power flow problems. The complete optimal power flow problem is solved through a sequence of quadratic subproblems, each of which has a quadratic objective function and a set of linearized equality constraints. These equality constraints include both the power flow equations and a set of active inequality constraints on variable bounds. The quadratic subproblems differ primarily in the different sets of active inequality constraints that are being enforced. As always, the load flow equations are satisfied in each subproblem.

This new approach to solving the classical OPF problem based on an explicit Newton formulation has received considerable attention [7]. The key to this approach is a direct simultaneous solution for all of the unknowns in the Lagrangian function on each iteration. "Each iteration minimizes a quadratic approximation of the Lagrangian. For any given set of binding constraints the process

converges to the Kuhn-Tucker conditions in a few iterations."[7] It appears that the solution effort is proportional to the size of the system being evaluated, and is relatively independent of the number of binding inequalities.

The interfacing of the equality constrained quadratic programming subproblems with the inequality constrained quadratic programming complete problem is still a major area of research. It requires a clever mechanism of identifying and enforcing the relatively small number of inequality constraints that are active at the optimal solution. This technique also requires the evaluation of a bordered Hessian matrix dimensioned N x N where N is four times the number of busses plus the number of tap changing under load (TCUL) transformers. It is also no trivial task to identify the active inequality constraints for each subproblem and to update the variables which involves a "move vector". As stated earlier, this method appears promising; however, more work is needed.

Another approach, the quasi-Newton method, utilizes second order information contained in an iteratively constructed reduced Hessian matrix [8]. In each iteration, this method obtains a descent

direction by operating on the reduced gradient with an approximation of the factors of the symmetrical but dense reduced Hessian. This technique has large computation and storage requirements. More recently, improvements to this technique have been made so that it approaches quadratic convergence [9].

CHAPTER III

GENERALIZED NETWORK FLOW PROGRAMMING (GNFP)

3.1. Literature Survey of GNFP

Jensen and Barnes [1] provide several concise historical accounts of the major works in the evolution of Network Flow Programming. They begin with the pioneering works of Hitchcock (1941), Kantorovich (1942), and Koopmans (1947). These works in optimization problems involving flows in networks were the first attempts at solving the transportation problems as networks. The 1950's, according to [1], saw the development of network algorithms for optimization problems such as the assignment, transportation, maximum flow, and the pure minimum cost flow. The transportation problem was solved with network flow programming by Dantzig (1951), Flood (1953), Charnes and Cooper (1954), Gleyzal (1955), Ford and Fulkerson (1956), Munkres (1957), Eisemann (1957), and Dennis (1958). The assignment problem was addressed by Kuhn (1955,1956), Motzkin (1956), and Munkres (1956). Dantzig (1956) and

Ford and Fulkerson (1957) considered the maximum flow problem. Jensen and Barnes [1] also mention works by Fulkerson (1961) and Orden (1956) with algorithms for solving the pure minimum cost flow problem.

The 1960's brought books by Dantzig (1963), Charnes and Cooper (1961), and Ford and Fulkerson (1962) that discussed the works up to this time. The Ford and Fulkerson book is called by Jensen and Barnes [1] a "classic of network flow programming and for many years was the only book in the field." Johnson's triple label method in 1966 had great application in representing trees in network flow programming. Innovative techniques such as preorder traversal lists were introduced by Glover, Klingman, and Stutz (1974). This resulted in a reported 10% reduction in computation time from using triple labeling [1].

Shortest path problems were first described by Dijkstra (1959) and Whitting and Hillier (1960). Jensen and Barnes [1] list other works in this area by Hu (1969), Yen (1971), Hoffman and Winograd (1972), and Spira (1973).

The generalized network problem dates back to early works by

Dantzig (1963) and Charnes and Cooper (1961). Early pioneers like Eisemann (1964), Lourie (1964), and Balas and Ivanescu (1964) implemented primal procedures to the generalized problem. Maurras (1972) and Glover, Klingman, and Stutz (1973) used the three-pointer representation to implement primal algorithms for the generalized min-cost flow problem. Jensen and Bhaumik (1977) presented a dual incremental approach [1]. For a more detailed account, refer to Jensen and Barnes [1].

3.2 <u>GNFP Notation and Concepts</u>

Generalized Network Flow Programming (GNFP) is based on Linear Programming (LP). Any problem that can be solved with GNFP can be solved with LP. However, by the natural structure of some problems, their solution is much more efficiently accomplished with GNFP. Many problems considering distribution, water flow, and scheduling can be modeled as networks. As discussed by Jensen and Barnes [1], a network is a collection of nodes and arcs (see Figure 3.1). Some systems that are represented by networks have the characteristic of flow, and models of these are called network flow

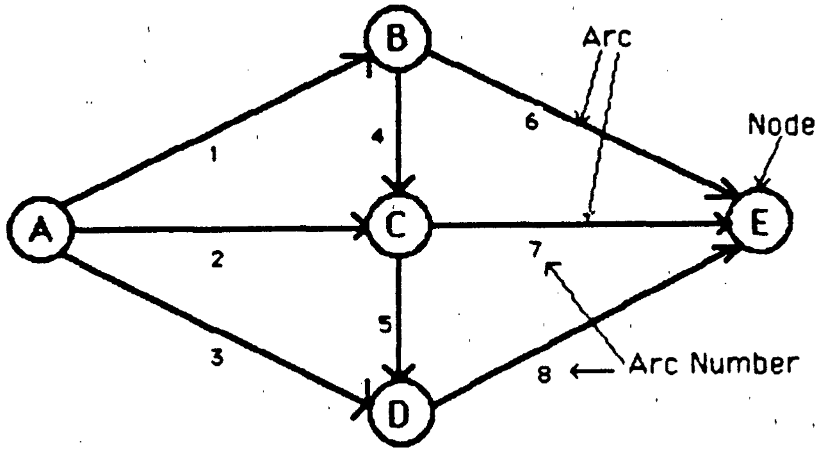


Figure 3.1 Network

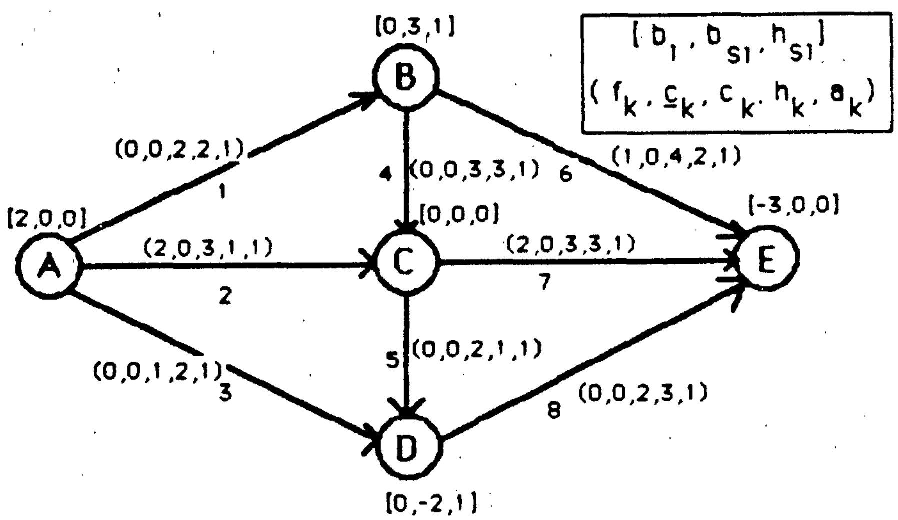


Figure 3.2. Network Flow Problem with Solution

models. The description of such models is completely contained in its parameters. There are parameters associated with the arcs and the nodes. As seen in Figure 3.2, a node i has three parameters. They are fixed external flow (b_i), slack (or variable) external flow capacity (b_{si}), and slack flow cost (h_{si}). Slack external flow is extra flow that may enter (or leave) the system at a node, but it's not mandatory. The slack flow that is actually used at node i is designated f_{si}. This cost is for each unit of slack external flow. The fixed external flow is shown as positive for required flow into the system and negative for required flow out of the system. Also, a positive cost is an outlay and a negative cost is a revenue.

Again, in Figure 3.2, an arc k has five parameters. The first is flow (f_k), which is being solved for. The second is a lower bound ($\underline{c}_k$), which is the least amount that can flow over the arc. The third is a capacity (c_k), which is the upper bound or maximum amount of flow allowable on the arc. The fourth is the cost (h_k) for each unit of flow on the arc. And, lastly, there is a gain parameter (a_k) associated with

each arc. This a_k is the relative increase or decrease in the amount of flow as it travels over the arc. An a_k between 0 and 1 represents a loss of flow and an a_k greater than one represents an increase in flow.

As in Jensen and Barnes [1], a node i is an element of the list of nodes, N = [1,2,3, . . . ,i, . . . n]; and, an arc k is an element of the list of arcs, M = [1,2,3, . . . ,k, . . . m]. An arc may also be defined by an ordered pair of nodes (i,j). In this representation, i is the *origin node* of arc k and j is the *terminal node* of arc k. This leads to the notation of the origin and terminal lists

$$\mathbf{O} = [\, o_1, o_2, \ldots, o_n \,]$$

$$\mathbf{T} = [\, t_1, t_2, \ldots, t_n \,]$$

where o_k and t_k are the origin and terminal nodes of arc k. In Figure 3.1, **O** = [A,A,A,B,C,B,C,D] and **T** = [B,C,D,C,D,E,E,E]. Thus, the list of all arcs that originate at node i is $M_{Oi} = [\, k \mid o_k = i \,]$. And the list of all arcs that terminate at node i is $M_{Ti} = [\, k \mid t_k = i \,]$. Again, in Figure 3.1, M_{OC} = [5,7] and M_{TC} = [2,4].

Generalized Network Flow Programming attempts to solve for the arc flows, f_k, and slack flow, f_{si}, that will minimize cost. If b_{si} (the slack external flow) is positive (negative) f_{si} enters (leaves) the network and is bounded by $0 \le f_{si} \le |b_{si}|$. So, the objective function to be minimized is

$$H(f) = \sum_{k=1}^{m} h_k(f_k) + \sum_{i=1}^{n} h_{si}(f_{si})$$

At each node, conservation of flow must be maintained. This means

TOTAL ARC FLOW LEAVING THE NODE - TOTAL ARC FLOW ENTERING THE NODE - FIXED EXTERNAL FLOW AT THE NODE = 0 ,

or

$$\sum_{k \in M_{Oi}} f_k - \sum_{k \in M_{Ti}} a_k f_k - b_i = 0 \qquad i = 1,2,\ldots,n$$

The constraints of arc flow limits must also be enforced. That is

$$\underline{c}_k \le f_k \le c_k \qquad \text{for all } k.$$

Jensen and Barnes express the dual of the generalized minimum cost flow problem in terms of the dual variables, π_i ($i=1,\ldots,n$). The complementary slackness conditions for optimality are:

$$+\pi_i - a_k \pi_j = -h_k \qquad \text{for } 0 < f_k < c_k \tag{3.1}$$

$$f_k = 0 \qquad \text{for } \pi_i - a_k \pi_j > -h_k \tag{3.2}$$

$$f_k = c_k \qquad \text{for } \pi_i - a_k \pi_j < -h_k \tag{3.3}$$

GNFP finds arc flows, f_k, that form a basis then adds and deletes arcs that maintain a basis and minimize the objective function. This continues until the optimality conditions in Equations (3.1) - Equations (3.3) are satisfied. Optimality is then guaranteed [1].

Now, since a power system can be represented as a collection of nodes (busses) and arcs (transmission lines) with gains (power loss) down the lines from bus to bus, and external flow (P and Q loads/generations), it is intuitively appealing to use our knowledge of Generalized Network Flow Programming to help solve the OPF.

CHAPTER IV

GENERALIZED NETWORK FLOW PROGRAMMING IN SOLVING THE OPTIMAL POWER FLOW PROBLEM

4.1. Problem Formulation

The following is a restatement of the Optimal Power Flow problem as seen in Chapter II.

$$\text{Minimize } Z = \sum_{i=1}^{n} C_{gi}(P_{gi}) \tag{4.1}$$

subject to:

$$\sum_{j=1}^{n} \mathit{Real}\,[\, V_i^*(V_i - V_j)y_{ij} + V_i^* V_i y_{ij}'/2] - P_{i,inj} = 0, \quad i = 1,2,\ldots,n \tag{4.2}$$

$$\sum_{j=1}^{n} -\mathit{Imag}\,[\, V_i^*(V_i - V_j)y_{ij} + V_i^* V_i y_{ij}'/2] - Q_{i,inj} = 0, \quad i = 1,2,\ldots,n \tag{4.3}$$

$$\begin{gathered} V_{imin} \le V_i \le V_{imax} \\ P_{imin} \le P_{gi} \le P_{imax} \\ Q_{imin} \le Q_{i,inj} \le Q_{imax} \\ \text{Line min} \le S_{ij} \le \text{Line max} \end{gathered} \tag{4.4}$$

First, notice that P_{gi} is the decision variable and is part of $P_{i,inj}$; ($P_{i,inj} = P_{gi} - P_{li}$). Equations (4.2) and (4.3) are respectively called the Real and Reactive Power Mismatch Constraints. They merely state conservation of power flow at each bus. The last constraint enforces the limit on the amount of real power on a line (line load limit). One can readily see that the primary difficulty in finding the optimal solution lies in the nonlinearity of the problem.

Look at the two equality constraints; the Mismatch Equations.

$$\sum_{j=1}^{n} \mathit{Real}\,[\, V_i^*(V_i - V_j)y_{ij} + V_i^* V_i y_{ij}'/2] - P_{i,inj} = 0, \qquad i=1,2,\ldots,n \tag{4.5}$$

$$\sum_{j=1}^{n} -\mathit{Imag}\,[\, V_i^*(V_i - V_j)y_{ij} + V_i^* V_i y_{ij}'/2] - Q_{i,inj} = 0, \qquad i=1,2,\ldots,n \tag{4.6}$$

Equation (4.5) is the real power mismatch equation. Since y'_{ij} has no real component, $V_i^* V_i y'_{ij/2}$ can be eliminated from Equation (4.5). This yields

$$\sum_{j=1}^{n} Real\,[\, V_i^*(V_i - V_j)y_{ij}\,] - P_{i,inj} = 0, \qquad i=1,2,\ldots,n \qquad (4.7)$$

If the power flow from node i is divided into the positive power flow from i and the negative power flow from i the first term in Equation 4.7 becomes

$$\sum_{j=1}^{n} Real\,[\, V_i^*(V_i - V_j)y_{ij}\,] =$$

$$\sum_{h=1}^{w} Real\,[\, V_i^*(V_i - V_h)y_{ih}\,] + \sum_{l=1}^{u} Real\,[\, V_i^*(V_i - V_l)y_{il}\,]\,, \quad \begin{array}{l} i=1,2,\ldots,n \\ n=w+u \end{array} \qquad (4.8)$$

where the sum over all l is the positive power flow from i and the sum over all h is the negative power flow from i One way to view this is negative power flow from a node is the same as positive flow into that node. Now, look at the negative flow from i. For reasons that become apparent later, re-express the negative flow from i as

$$\sum_{h=1}^{w} Real\,[\, V_i^*(V_i - V_h)y_{ih}] =$$

$$\sum_{h=1}^{w}\left(\left[\frac{Real[V_i^*(V_i-V_h)y_{ih}] + Real[V_h^*(V_h-V_i)y_{ih}]}{Real[V_h^*(V_h-V_i)y_{ih}]} - 1\right] * Real[V_h^*(V_h-V_i)y_{ih}]\right) \tag{4.9}$$

Algebraic manipulation of the right hand side of Equation 4.9 will verify that the terms on both sides of the equal sign are the same.

Now, recall the Jensen and Barnes [1] notation. Let

M_{Ti} = {all arcs that terminate at node i}

M_{Oi} = {all arcs that originate at node i}

k = index of arcs

With $k \epsilon M_{Ti}$ (set of all arcs terminating at bus i), the quantity inside the parenthesis in Equation 4.9 can be multiplied by -1 and called a_k;

denote a_k =

$$1 - \frac{Real[V_i^*(V_i-V_h)y_{ih}] + Real[V_h^*(V_h-V_i)y_{ih}]}{Real[V_h^*(V_h-V_i)y_{ih}]}$$

$$= \frac{-Real[V_i^*(V_i-V_h)y_{ih}]}{Real[V_h^*(V_h-V_i)y_{ih}]} \tag{4.10}$$

Then Equation 4.5 becomes,

$$-\sum_{k\in M_{Ti}} a_k \, Real\,[V_h^*(V_h-V_i)y_{ih}] + \sum_{l=1}^{u} Real\,[\,V_i^*(V_i-V_l)y_{il}] - P_{i,inj} = 0, \quad i=1,2,\ldots,n \tag{4.11}$$

Now, looking at Equation 4.11, let
the positive real power flow from h to i (call this arc k) be
$P_k = Real[V_h^*(V_h-V_i)y_{ih}]$
where $k\in M_{Ti}$

and the positive real power flow from i to l be
$P_k = Real\,[\,V_i^*(V_i-V_l)y_{il}]$
where $k\in M_{Oi}$

Therefore, Equation 4.11 becomes

$$-\sum_{k\in M_{Ti}} a_k P_k + \sum_{k\in M_{Oi}} P_k - P_{i,inj} = 0 \tag{4.12}$$

Now, consider Equation 4.6.

$$\sum_{j=1}^{n} -Imag[\,V_i^*(V_i-V_j)y_{ij} + V_i^*V_iy_{ij}'/2\,] - Q_{i,inj} = 0, \quad i=1,2,\ldots,n \tag{4.13}$$

So, with the same arguments that led from Equation 4.5 to Equation 4.12, it is shown that Equation 4.6 yields

$$-\sum_{k \in M_{Ti}} a_k' Q_k + \sum_{k \in M_{Oi}} Q_k - Q_{i,inj} = 0 \qquad (4.14)$$

where $a_k' =$

$$1 - \frac{-Imag[V_i^*(V_i-V_h)y_{ih} + V_i^*V_iy_{ih}'/2] - Imag[V_h^*(V_h-V_i)y_{ih} + V_h^*V_hy_{ih}'/2]}{-Imag[V_h^*(V_h-V_i)y_{ih} + V_h^*V_hy_{ih}'/2]}$$

$$= -\frac{Imag[V_i^*(V_i-V_h)y_{ih} + V_i^*V_iy_{ih}'/2]}{Imag[V_h^*(V_h-V_i)y_{ih} + V_h^*V_hy_{ih}'/2]} \qquad (4.15)$$

Q_k = positive reactive power flow from h to i

$= -Imag[V_h^*(V_h-V_i)y_{ih} + V_h^*V_hy_{ih}'/2]$

where $k \in M_{Ti}$

Q_k = positive reactive power flow from i to l

$= -Imag[V_i^*(V_i-V_l)y_{il} + V_i^*V_iy_{il}'/2]$

where $k \in M_{Oi}$

These a_k and a_k' are referred to as gain factors for flow on arc k. The gain factor, a_k, since it is always greater than 0 and less than 1, represents the decrease in real power flow as it travels down an arc. This actually makes sense, physically. Since the real power

flow down a line from j to i is *Real* $[V_j^*(V_j-V_i)y_{ij}]$ and the flow from i to j is *Real* $[V_i^*(V_i-V_j)y_{ij}]$, one number (say from j to i) is positive and the other (say from i to j) is negative. By the mathematical nature of this problem, they are never the same sign. Thus, the flow is toward i. And the actual loss of real power is the algebraic sum of the two. Therefore, the relative loss is the sum divided by the flow from j to i. And, since the gain is (1 - loss), Equation 4.10 actually makes sense as a gain factor. The expression in parenthesis in Equation 4.9 could have just as easily been

$$\frac{\mathit{Real}[V_i^*(V_i-V_h)y_{ih}]}{\mathit{Real}[V_h^*(V_h-V_i)y_{ih}]}$$

However, it was purposely expressed as such to show the logical, intuitive meaning of gain and loss. In GNFP, these gain factors are linear. However, it is known that power loss down a line varies as $(\text{current})^2$. Thus, these gain factors are linear approximations. Several problems have been examined and it appears that these gain factors are very robust and are very good approximations. This will be

touched on in Chapter V.

One point must be discussed. Transformers have two effects. A transformer, with tap ratio **a**, between bus i and bus j will affect the admittance elements y_{ij}, y_{ji}, and y_{ii}; and the transformer will affect the flow of power down the line in the following way. The admittance elements y_{ij} and y_{ji} become $y_{ij}/\mathbf{a}$ and $y_{ji}/\mathbf{a}$. And the diagonal element which was $y_{ii} = \sum_{j \neq i} y_{ij}$ becomes

$$y_{ii} = [\, y_{i1} + y_{i2} + \ldots + y_{ij}/\mathbf{a}^2 + \ldots + y_{in}]$$

The effect on power flow is shown in Figure 4.1.

$$S_{ij}^{*} = V_i^{*} [\, (V_i - V_j) y_{ij/\mathbf{a}} + V_i y_{ij/\mathbf{a}} (1/\mathbf{a} - 1)\,]$$

$$= V_i^{*} [\, V_i y_{ij/\mathbf{a}^2} - V_j y_{ij/\mathbf{a}}]$$

$$= V_i^{*} [\, V_{i/\mathbf{a}} - V_j\,] y_{ij/\mathbf{a}}$$

And, similarly, $S_{ji}^{*} = V_j^{*} [V_j - V_i/\mathbf{a}]\, y_{ij}$.

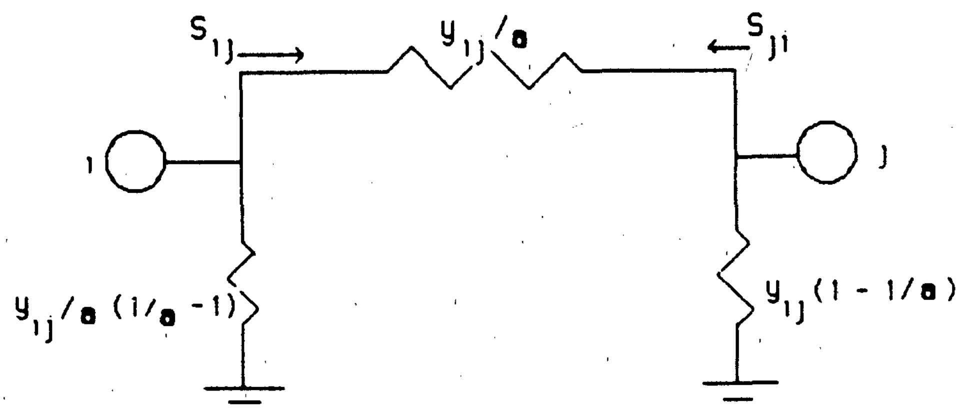


Figure 4.1. Transformer Electrical Model

This complex power flow can be separated into its real and reactive components, P_k and Q_k, as before. This compares to the flow, without a transformer,

$$S_{ij}^* = V_i^* [\, V_i - V_j \,] y_{ij} \quad \text{and}$$

$$S_{ji}^* = V_j^* [\, V_j - V_i \,] y_{ij}.$$

Now, with Equations 4.12 and 4.14, the OPF problem can be formulated as a Generalized Network Flow Programming problem.

$$\text{Minimize } Z = \sum_{i=1}^{n} C_{gi} (P_{gi})$$

subject to:

$$-\sum_{k \in M_{Ti}} a_k P_k + \sum_{k \in M_{Oi}} P_k - P_{i,inj} = 0, \qquad i = 1, \ldots, n$$

$$-\sum_{k \in M_{Ti}} a_k' Q_k + \sum_{k \in M_{Oi}} Q_k - Q_{i,inj} = 0, \qquad i = 1, \ldots, n$$

$$V_{imin} \le V_i \le V_{imax}$$
$$P_{imin} \le P_{gi} \le P_{imax}$$
$$Q_{imin} \le Q_{i,inj} \le Q_{imax}$$
$$\text{Line min} \le S_{ij} \le \text{Line max}$$

where

$$a_k = -\frac{Real[V_i^*(V_i-V_h)y_{ih}]}{Real[V_h^*(V_h-V_i)y_{ih}]}$$

$$a_k' = -\frac{Imag[V_i^*(V_i-V_h)y_{ih} + V_i^* V_i y_{ih}'/2]}{Imag[V_h^*(V_h-V_i)y_{ih} + V_h^* V_h y_{ih}'/2]}$$

$$P_k = Real[V_h^*(V_h-V_i)y_{ih}]$$
where $k \epsilon M_{Ti}$

$$P_k = Real[V_i^*(V_i-V_l)y_{il}]$$
where $k \epsilon M_{Oi}$

$$Q_k = -Imag[V_h^*(V_h-V_i)y_{ih} + V_h^* V_h y_{ih}'/2]$$
where $k \epsilon M_{Ti}$

$$Q_k = -Imag[V_i^*(V_i-V_l)y_{il} + V_i^* V_i y_{il}'/2]$$
where $k \epsilon M_{Oi}$

$$P_{i,inj} = P_{gi} - P_{li}$$

$$Q_{i,inj} = Q_{gi} - Q_{li}$$

4.2. Solution Algorithm

Following the general algorithm in Section 2.4.b., a summary of the steps of the solution technique is shown in Figure 4.2. The exact steps are:

Step 1 - Overall solution time is dependent on initial estimates. It is recommended that the initial generation pattern estimate be obtained from the method of equal incremental cost rates (ignoring penalty factors).

Step 2 - Since the GNFP method does not allow shunt impedance ties to ground, elements of this type must be modeled as fixed P, Q loads. These values are updated according to bus voltages.

Step 3 and 6 - A conventional power flow program is used with the latest generation estimates. Swing bus power is revised, and interchange requirements are met. Reactive power limits at P-V busses are handled in the conventional manner.

Step 4 - Arc gains are calculated by the method described in the preceeding section.

Step 5 - Arc gains and piecewise-linear incremental cost

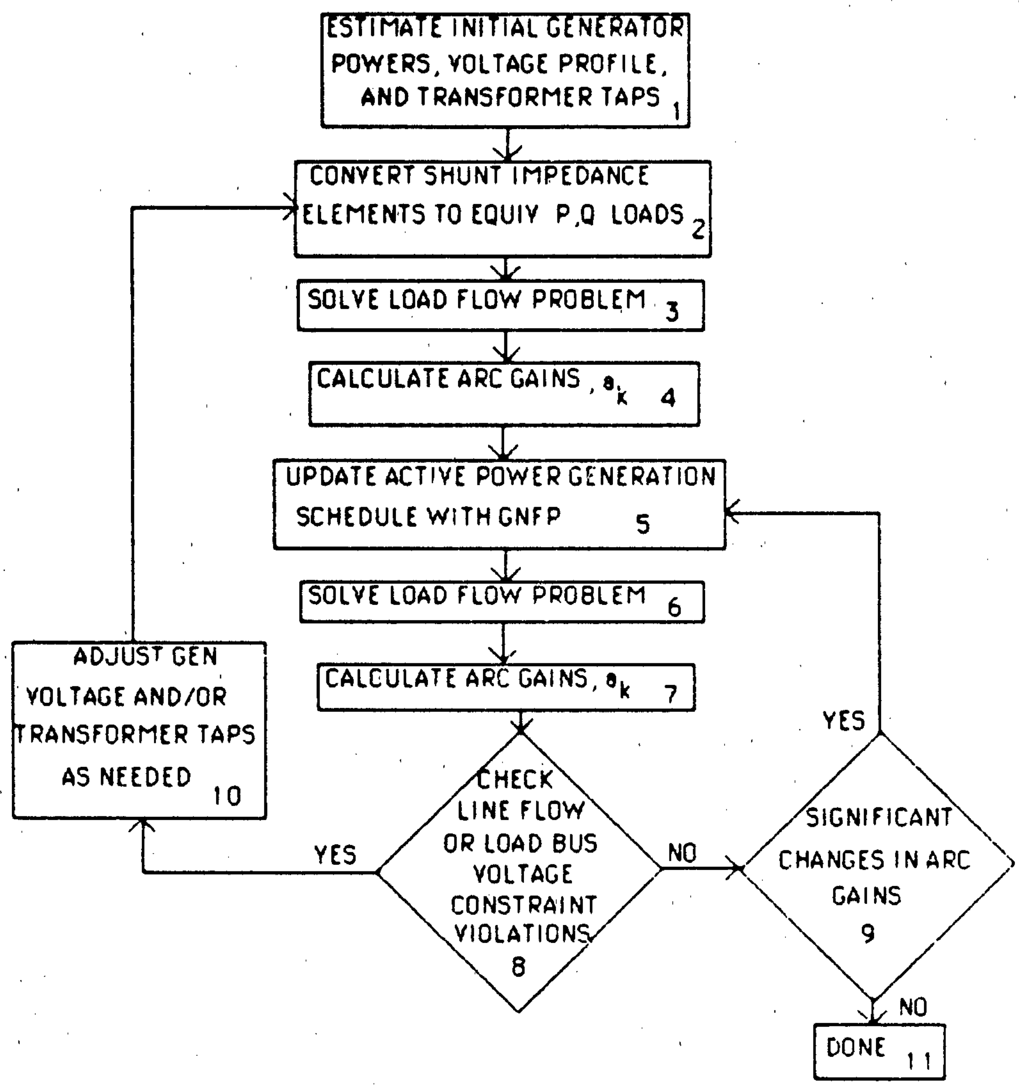


Figure 4.2 Flow Chart of Solution Technique

curves are used by the GNFP program to determine a new active power generation schedule which minimizes total generation cost. Active power flow limits are observed, and generator location with respect to loads is considered via the arc gains. Swing bus power is estimated here, and is solved precisely in Step 6.

Step 7 - Update arc gains.

Step 8 - MVA line flow limits are checked. If exceeded, the active power limits in Step 5 are lowered appropriately to limit total MVA flow. Load bus voltage constraints are checked.

Step 9 - Gain changes less than ± 0.001 are ignored.

Step 10 - The procedure to modify generator voltages and/or transformer taps to relieve constraint violations is not mechanized at this time. Adjustments may call for voltages to be fixed at certain values, or Q injections/extractions, or some other measure deemed necessary. If this adjustment is needed, it must be performed by an engineer who is familiar with the network. This author believes, however, that in most cases, a well prepared starting estimate (Step 1) will diminish the need for Step 10.

There is no guarantee that this procedure will always find a

feasible solution because one may not exist. In other words, there may be no method in Step 10 to prevent constraint violations. However, GNFP detects infeasibility. Further study is needed in this area.

Appendix 1 shows the Fortran IV program that runs on a CDC/Dual Cyber 170/750 that takes the system's data and performs a Gauss-Seidel (GS) iterative scheme to solve the load flow problem and calculate the voltages at each bus. The system data is the y_{ij} and y'_{ij} of each line, the **a** value for each transformer, the V at all non-P-V busses, and the shunt MVar at the appropriate busses. The admittance matrix is built by making the off-diagonal elements equal to minus the line admittance and the diagonal elements are the sum of the line admittances. With these voltages and the admittance matrix (used in GS), the program computes the bus voltages, the direction of flow, and the gain factors a_k and a_k' according to Equations 4.10 and 4.15.

The GS iterative solution technique for the load flow is well known. It starts by estimating voltages for all the busses except the slack bus, which has a specified and fixed voltage. With the complex power known at all P-Q busses and the real power and voltage

magnitude known at all P-V busses, the GS technique procedes from the second bus (bus 1 being the slack bus) through the n^{th} (last) bus solving

$$V_i = 1/Y_{ii} \left[\frac{P_{i,inj} - jQ_{i,inj}}{V_i^*} - \sum_{\substack{j=1 \\ j\neq i}}^{n} Y_{ij} V_j \right] \qquad (4.16)$$

where $P_{i,inj}$ = real power injection at bus i
$Q_{i,inj}$ = reactive power injection at bus i
Y_{ij} = admittance matrix element i,j
V_i = complex voltage at bus i

The updated voltages are used in subsequent solutions to the equation. This process continues until the changes in the voltages at the next iteration are negligible. Once the voltages are computed, the load flows and gains are calculated. It must be noted that P-V busses require a little more effort [10].

Since the Q_i is not known for a P-V bus it must be calculated as follows:

$$Q_i = - \mathit{Imag}(V_i^* \sum_{j=1}^{n} Y_{ij} V_j) .$$

It is then put into Equation 4.16 and the V_i is calculated. But, now, this

V_i must be corrected to agree with the specified magnitude. So, this V_i must be multiplied by the ratio of the specified constant magnitude of V_i to the magnitude of the V_i just found.

4.3. Generalized Network Flow Programming Approach

With these voltages just found, the gain factors can be computed and the process could continue to the GNFP codes [1] and solve the load flow problem again for $P_{g,swing}$. This would be a check to see how well the linearization of the problem fit. It is merely a solution to the constraints (load flow equations) with a "dummy" objective function. Jensen and Barnes' code requires external flows at the nodes, gains on the arcs, and costs. The external flows are positive for generations and negative for loads. The gains are the a_k and a_k' found in the previously discussed GS program. The costs are arc costs and cost per unit for slack external flow.

This would be merely an estimate to the solution to the load flow problem for the P generated at the swing bus. But what has been done up to now is not of major note other than it shows that the load

flow problem and the OPF can be formulated as a GNFP problem. There are better methods to solve the Load Flow problem. However, the next step is the reason for the entire effort of setting the OPF up as a GNFP problem.

Assume that each of the generators has a cost functon and generation requirements such as those shown in Table 5.2. The problem now is to produce that amount of real power at *each* generator that will minimize generation costs and still maintain feasibility.

Solution techniques to this problem do exist. There are a few production codes on the market and in development. However, most require calculation of Jacobian and Hessian matrices for nonlinear optimization techniques. These techniques require large numbers of calculations and are prone to numerical round-off error. Therefore,these existing techniques are time consuming on a big computer. Most real world systems require hours of CPU time to solve. The technique developed here is simple, straight-forward, and fast.

Take the GNFP model that was developed previously and construct linear approximations to the convex nonlinear cost functions for each generator, take the gains, a_k, that are obtained from the GS

program that solved the load flow problem, and solve the flow network with the GNFP code. This yields the optimal P_{gi} for *each* generator.

This is the optimum generation scheduled, but one must insure that the solution is still feasible. What the GNFP codes do is minimize the objective function subject to the Real Power mismatch constraints (4.2) and the constraints on P_{gi} and line load. So, the real power generations at each generator are put back into the GS program and the load flow problem is solved again to make sure the Reactive Power mismatch constraint (4.3) and the constraints on V_i and $Q_{i,inj}$ were not violated. If limits are violated, adjustments are made and another iteration is begun.

A point of interest is that other load flow solution techniques are often better than Gauss-Seidel. However, they are more difficult to program. These include the Newton-Raphson Method, Stott's Method, etc. Any of these can be used to obtain good estimates of the V_i's to be used in calculating the a_k and a_k'.

4.4. 5 Bus Illustrative Example

At this point, an example is appropriate. This 5-bus example from Stagg [10] (see Figure 4.3) illustrates the OPF concepts.

LINE DATA

TERMINAL FROM	TERMINAL TO	ADMITTANCE(y_{ij})	TOTAL MVAR CHARGING(y'_{ij})
A	B	5.00 -j15.00	0.0 +j0.06
A	C	1.25-j3.75	0.0 +j0.05
B	C	1.667-j5.00	0.0 +j0.04
B	D	1.667-j5.00	0.0 +j0.04
B	E	2.50-j7.50	0.0 +j0.03
C	D	10.00-j30.00	0.0 +j0.02
D	E	1.25-j3.75	0.0 +j0.05

BUS DATA

BUS	ASSUMED VOLT. MAG.	ANG.	GENERATION P(MW)	Q(MVAR)	LOAD P(MW)	Q(MVAR)	COST FUNCTION
A	1.06	0.0	?	?	-	-	$106+.55P_{g1}+.008P_{g1}^2$
B	1.00	0.0	40*	30*	20	10	$110+.64P_{g2}+.0064P_{g2}^2$
C	1.00	0.0	-	-	45	15	
D	1.00	0.0	-	-	40	5	
E	1.00	0.0	-	-	60	10	

*Estimates

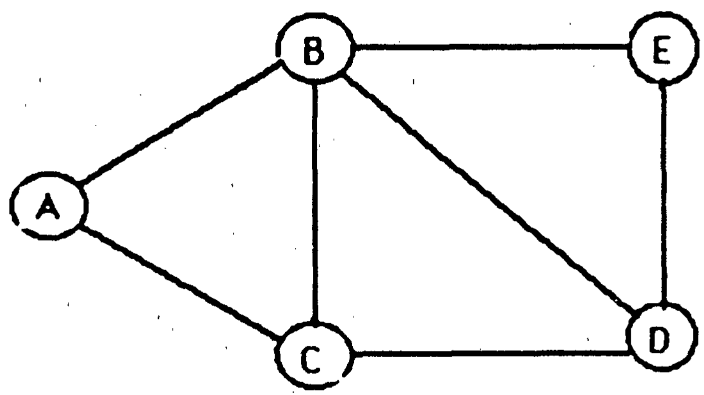


Figure 4.3 5 Bus Example

Thus, the OPF problem, from equations 4.1 through 4.4, becomes

$$\text{Min } Z = 106 + .55P_{g1} + .008P_{g1}^2 + 110 + .64P_{g2} + .0064P_{g2}^2$$

subject to

(BUS A)

$$\text{Real}[V_A^*(V_A-V_B)(5.0-j15.0) + \text{Real}[V_A^*(V_A-V_C)(1.25-j3.75) - P_{g1} = 0$$

$$-\text{Imag}[V_A^*(V_A-V_B)(5.0-j15.0)+V_A^*V_A(0.0+j0.03)] - \text{Imag}[V_A^*(V_A-V_C)(1.25-j3.75)+V_A^*V_A(0.0+j0.025)] - Q_{g1} = 0$$

(BUS B)

$$\text{Real}[V_B^*(V_B-V_A)(5.0-j15.0) + \text{Real}[V_B^*(V_B-V_C)(1.667-j5.00) + \text{Real}[V_B^*(V_B-V_D)(1.667-j5.00) + \text{Real}[V_B^*(V_B-V_E)(2.5-j7.50) - 40 + 20 = 0$$

$$-\text{Imag}[V_B^*(V_B-V_A)(5.0-j15.0)+V_B^*V_B(0.0+j0.03)] - \text{Imag}[V_B^*(V_B-V_C)(1.667-j5.00)+V_B^*V_B(0.0+j0.02)] - \text{Imag}[V_B^*(V_B-V_D)(1.667-j5.00)+V_B^*V_B(0.0+j0.02)] - \text{Imag}[V_B^*(V_B-V_E)(2.5-j7.50)+V_B^*V_B(0.0+j0.015)] - 30 + 10 = 0$$

and so on.

Notice the inclusion of the line charging ($y'_{ij}/2$) in the imaginary equations.

Or, in the GNFP formulation, this becomes, equivalently,

$$\text{Min } Z = 106 + .55P_{g1} + .008P_{g1}^2 + 110 + .64P_{g2} + .0064P_{g2}^2$$

subject to

$$\text{Real}\,[V_A^*(V_A-V_B)(5.0-j15.0)] + \text{Real}[V_A^*(V_A-V_C)(1.25-j3.75)] - P_{g1} = 0$$

(BUS A)

$$-\text{Imag}\,[V_A^*(V_A-V_B)(5.0-j15.0)+V_A^*V_A(0.0+j0.03)] - \text{Imag}[V_A^*(V_A-V_C)(1.25-j3.75) + V_A^*V_A(0.0+j0.025)] - Q_{g1} = 0$$

$$-\left[\frac{-\text{Real}[V_B^*(V_B-V_A)(5.0-j15.0)]}{\text{Real}[V_A^*(V_A-V_B)(5.0-j15.0)]}\right] *\text{Real}\,[V_A^*(V_A-V_B)(5.0-j15.0)] + \text{Real}[V_B^*(V_B-V_C)(1.667-j5.00)] + \text{Real}[V_B^*(V_B-V_D)(1.667-j5.00)] + \text{Real}[V_B^*(V_B-V_E)(2.5-j7.50)] - 40 + 20 = 0$$

(BUS B)

$$-\left[\frac{-\text{Imag}[V_B^*(V_B-V_A)(5.0-j15.0) + V_B^*V_B(0.0+j0.03)]}{\text{Imag}[V_A^*(V_A-V_B)(5.0-j15.0) + V_B^*V_B(0.0+j0.03)]}\right] *\{-\text{Imag}[V_A^*(V_A-V_B)(5.0-j15.0) + V_B^*V_B(0.0+j0.03)]\}$$

$$- \text{Imag}[V_B^*(V_B-V_C)(1.667-j5.00) + V_B^*V_B(0.0+j0.02)] - \text{Imag}[V_B^*(V_B-V_D)(1.667-j5.00) + V_B^*V_B(0.0+j0.02)] - \text{Imag}[V_B^*(V_B-V_E)(2.5-j7.50) + V_B^*V_B(0.0+j0.015)] - 30 + 10 = 0$$

and so on.

One can easily see the two formulations are equivalent. So, by the solution technique, the line and bus data are input into the program in Appendix 1. Then this program solves the Load Flow problem to find estimates of the voltages and, subsequently, the direction of power flow and the gain factors. This OPF, with

piecewise-linear approximations to the cost functions as depicted in Figure 4.4, is then put into the GNFP codes and solved for the *optimal* P_{g1} and P_{g2}. These values are then inserted back into the Load Flow problem and solved again to insure that feasibility is maintained.

In the notation of Jensen and Barnes, the problem would appear as in Figure 4.4.

The Load Flow solution for voltages is

$$V_A = 1.06 \quad + j0.0$$
$$V_B = 1.04623 - j0.05126$$
$$V_C = 1.02036 - j0.08917$$
$$V_D = 1.01920 - j0.09504$$
$$V_E = 1.01211 - j0.10904$$

And the calculations of the gain factors are

ARC	Gain (a_k)
A-B	.9842
A-C	.9705
B-C	.9838
B-D	.9857
B-E	.9799
C-D	1.0000
D-E	1.0000

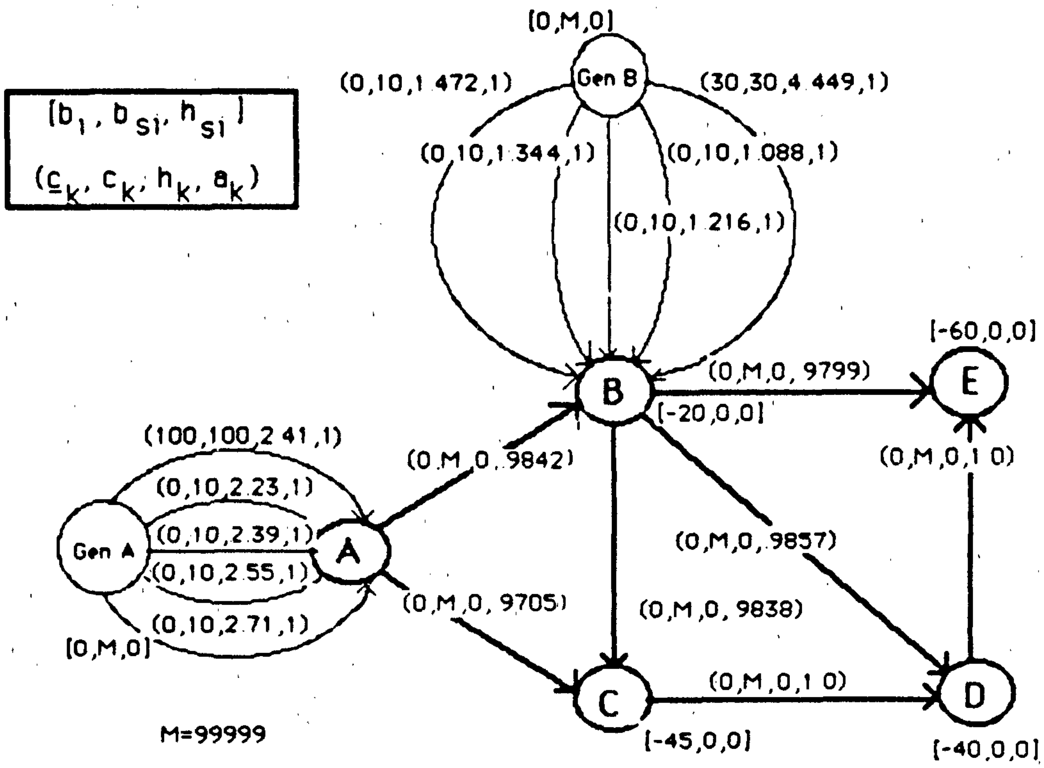


Figure 4.4 GNFP Representation

And, with a generation range on generator 1 of 100 to 140 MW and a generation range on generator 2 of 30 to 70 MW, from the GNFP solution,

$$P_{g1} = 100 \text{ MW}$$
$$P_{g2} = 68.65 \text{ MW}$$

for a total cost of 500.4 units. This generation schedule was then placed back into the GS scheme and the Load Flow problem was resolved. None of the constraints were violated and the solution is feasible.

4.5. Advantages of This Method

This method, unlike a Linear Programming approach, is an extremely fast solution technique to the linearized problem. The examples in the next chapter will illustrate its speed. The execution time is a linear function of the number of nodes plus the number of arcs (m+n). Other advantages are

1. It is a very robust method. Even with large variations in the bus voltages, the gain parameters are fairly stable.
2. It is easy to use. Once the GNFP data files are constructed,

they are easily editted and ready to re-run.

3. It is an intuitively appealing method, in that GNFP was originally developed to optimize flows and generation schedules taking into account losses of flow down a line.

CHAPTER V

EXAMPLES

5.1. 39 Bus System

5.1.1. System Description

This 39 bus example (Figure 5.1) is the New England System and is a classic system that is often used in checking OPF algorithms. It consists of 39 busses, 10 generators, 46 transmission lines, and 14 fixed tap transformers. Table 5.1 shows the data for this system.

5.1.2. Illustrative Example

To first look at the Load Flow problem, the Gauss-Seidel (GS) routine in Appendix 2 was used to solve for the voltages at each bus, the direction of flow, and the gain parameters for real power flow. This set of directions and gains was then used as input into the GNFP codes.

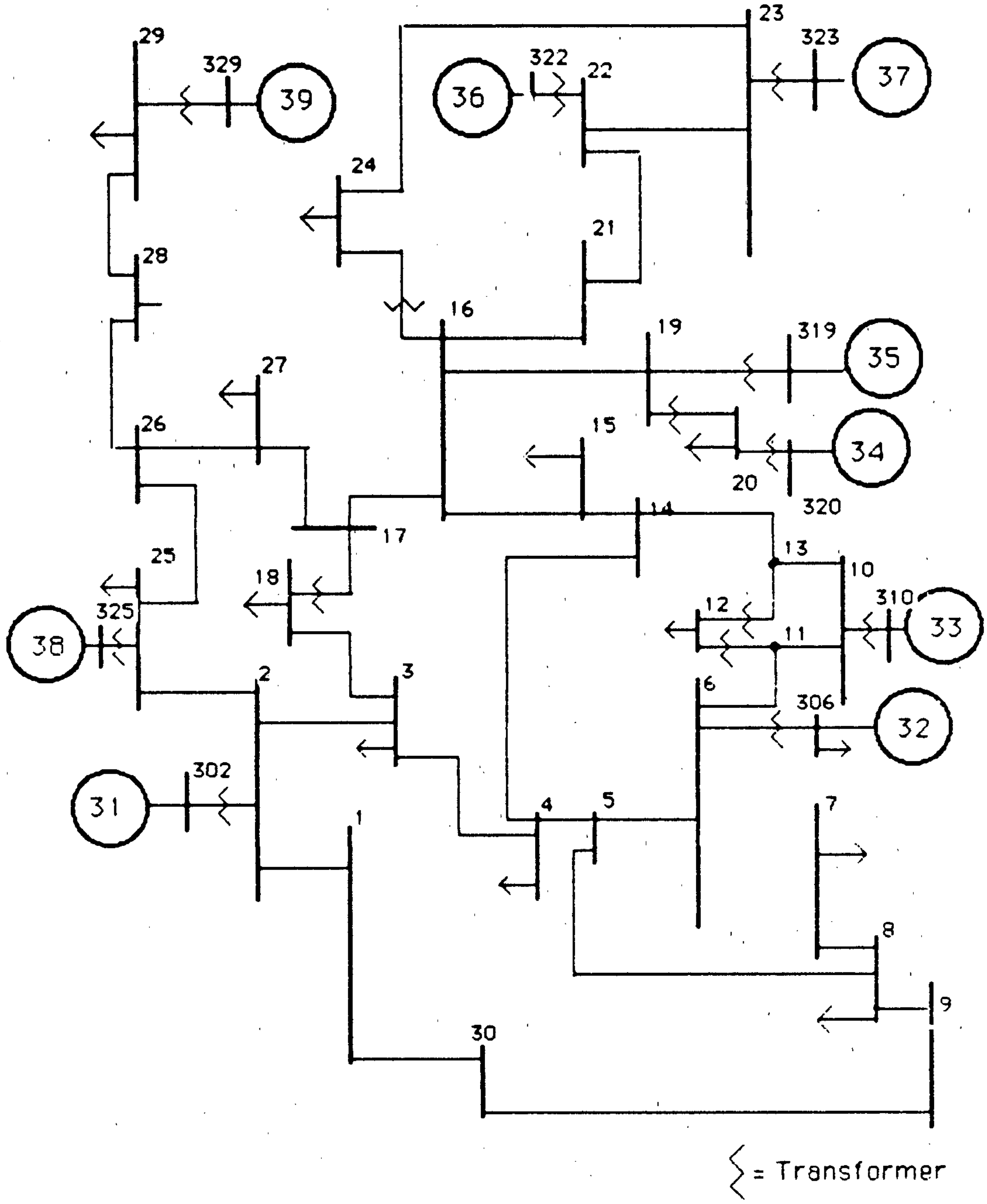


Figure 5.1 39 Bus Example System

Table 5.1 39 BUS DATA

LINE DATA

Terminal from	Terminal to	Percent Imped. R	Percent Imped. X	Total MVAR charging	P.U. tap	TAP RATIO min	TAP RATIO max
1	2	0.35	4.11	69.87			
1	30	0.10	2.50	75.00			
2	3	0.13	1.51	25.72			
2	25	0.70	0.86	14.60			
3	4	0.13	2.13	22.14			
3	18	0.11	1.33	21.38			
4	5	0.08	1.28	13.42			
4	14	0.08	1.29	13.82			
5	6	0.02	0.26	4.34			
5	8	0.08	1.12	14.76			
6	7	0.06	0.92	11.30			
6	11	0.07	0.82	13.89			
7	8	0.04	0.46	7.80			
8	9	0.23	3.63	38.04			
9	30	0.10	2.50	120.00			
10	11	0.04	0.43	7.29			
10	13	0.04	0.43	7.29			
12	11	0.16	4.35		1.006	1.006	1.006
12	13	0.16	4.35		1.006	1.006	1.006
13	14	0.09	1.01	17.23			
14	15	0.18	2.17	36.60			
15	16	0.09	0.94	17.10			
16	17	0.07	0.89	13.42			
16	19	0.16	1.95	30.40			
16	21	0.08	1.35	25.48			
16	24	0.00	3.50		1.000	0.900	1.100
17	18	0.00	3.50		1.000	0.900	1.100
17	27	0.13	1.73	32.16			
19	20	0.07	1.38		1.006	1.006	1.006
21	22	0.08	1.40	25.65			
22	23	0.06	0.96	18.46			

Table 5.1(cont)

23	24	0.22	3.50	36.10	
25	26	0.32	3.23	53.10	
26	27	0.14	1.47	23.96	
26	28	0.43	4.74	78.02	
26	29	0.57	6.25	102.90	
28	29	0.14	1.51	24.90	
2	302	0.00	1.81		1.025
6	306	0.00	2.50		1.070
10	310	0.00	2.00		1.070
19	319	0.07	1.42		1.070
20	320	0.09	1.80		1.009
22	322	0.00	1.43		1.025
23	323	0.05	2.72		1.000
25	325	0.06	2.32		1.025
29	329	0.08	1.56		1.025

BUS DATA

Bus	Voltage		Load		Generation				Shunt
No.	Mag.	Ang.	MW	MVAR	MW	MVAR	QMIN	QMAX	MVAR
1	1.019	-9.73	98.0	44.0					-70.0
2	1.044	-6.88							
3	1.025	-9.69	322.0	2.0					
4	0.999	-10.44	500.0	184.0					
5	1.001	-9.22							
6	1.003	-8.53							
7	0.992	-10.71	234.0	84.0					
8	0.990	-11.20	522.0	177.0					
9	1.016	-10.69	6.5	-67.0					-80.0
10	1.014	-6.12							
11	1.009	-6.94							
12	0.997	-6.95	8.0	88.0					

Table 5.1 (cont)

13	1.011	-6.84							
14	1.008	-8.52							
15	1.010	-8.93	320.0	153.0					
16	1.026	-7.52	329.0	32.0					
17	1.029	-8.55							
18	1.026	-9.42	158.0	30.0					
19	1.038	-2.77							
20	1.018	-4.05	680.0	103.0					
21	1.028	-5.08	274.0	115.0					
22	1.048	-0.61							
23	1.043	-0.81	274.5	84.6					
24	1.032	-7.40	309.0	-92.0					
25	1.054	-5.54	224.0	47.0					
26	1.049	-6.74	139.0	17.0					
27	1.034	-8.73	281.0	76.0					
28	1.049	-3.21	206.0	28.0					
29	1.049	-0.45	283.5	26.9					
30	1.017	-10.21							-100.0
302	1.050	-4.54			250.0	189.0	140.0	400.0	
306	0.982	0.0	9.2	4.6	555.5	219.0	0.0	300.0	
310	0.984	1.89			650.0	223.9	150.0	300.0	
319	0.997	2.47			632.0	185.0	0.0	250.0	
320	1.020	1.01			508.0	58.0	0.0	167.0	
322	1.049	4.36			650.0	225.1	-100.0	300.0	
323	1.064	7.05			560.0	111.1	0.0	240.0	
325	1.026	1.25			540.0	16.3	0.0	250.0	
329	1.027	6.61			830.0	31.1	-150.0	300.0	

Now, for the OPF problem, assume that each of the generators has a cost function and generation requirements as shown in Table 5.2. The problem now is to produce that amount of real power at each generator that will minimize generation costs and still maintain feasibility (that is, solve for the resultant V and Q profile insuring they're within limits). Or, in the GNFP formulation,

$$\text{Minimize } Z = \sum_{i=1}^{39} C_{gi}(P_{gi})$$

subject to:

$$-\sum_{k \in M_{Ti}} a_k P_k + \sum_{k \in M_{Oi}} P_k - P_{i,inj} = 0, \qquad i = 1,\ldots,39$$

$$V_{imin} \le V_i \le V_{imax}$$
$$P_{imin} \le P_{gi} \le P_{imax}$$
$$Q_{imin} \le Q_{i,inj} \le Q_{imax}$$
$$\text{Line min} \le S_{ij} \le \text{Line max}$$

where a_k, P_k, P_{gi}, $Q_{i,inj}$, S_{ij} as defined in Chapter III.

Taking the GNFP model built previously, linear approximations to the convex nonlinear cost function were constructed. These, along ·· the external flows and the gains, a_k, obtained from the GS

Table 5.2. GENERATION COSTS

Generator	Generation Reqt's(MW) Min	Max	Cost Function ($100)
32(swing)	250	700	$120 + .86P_G + .0092P_G^2$
31	100	250	$107 + .0004P_G^3$
33	350	800	$110 + .63P_G + .0070P_G^2$
34	350	800	$110 + .63P_G + .0070P_G^2$
35	250	600	$135 + .75P_G + .0076P_G^2$
36	350	800	$110 + .63P_G + .0070P_G^2$
37	225	750	$135 + .75P_G + .0076P_G^2$
38	210	720	$120 + .86P_G + .0092P_G^2$
39	375	1000	$110 + .63P_G + .0070P_G^2$

*P_G = amount of real power generated.

program were used in the GNFP code and the OPF solved. In 34 seconds, the APPLE IIE provided the following solution

	GENERATION(MW)	
GENERATOR	FROM LOAD FLOW	FROM GNFP OPF
32(swing)	590	580
31	250	100
33	650	685
34	632	685
35	508	600
36	650	685
37	560	619
38	540	570.2
39	830	688
TOTAL COST =	$3,558,317	$3,005,638

These results show that the solution from the OPF results in generation costs that are over $550,000 cheaper than the generation costs incurred from the Load Flow schedule. This is the optimum generation scheduled, but feasibility must be insured. So, one must take the real generations at each generator and put them back into the GS program and check to make sure the constraints on V_i and $Q_{i,inj}$ are not violated. None were violated.

A point of interest is the gain factors for real power flow.

With the change in P and Q generations from the Load Flow to the OPF, how large will the changes be in the gain factors? They are shown in Table 5.3. Only 5 of the 46 gains changed by more than .0025. This is evidence that the a_k's are very robust; i.e. the voltage can be changed rather radically without having major impacts on the gains.

Also examined were the effects of GS convergence on the a_k's. At iteration p, the voltage at bus i is calculated, V_i^p. Instead of replacing V_i^{p-1} with V_i^p, the GS technique will converge faster if $V_i^p = V_i^{p-1} + \Delta(V_i^p - V_i^{p-1})$. This Δ is called the acceleration factor. One can also have different factors for the real and the imaginary components of V_i. The iterations continue until the largest difference between successive voltages is no more than α, the convergence factor. Using an acceleration factor of 1.4 for both the real and imaginary parts, the GS program was run with a convergence parameter of α = 0.001 and again with α = 0.0001. The two runs with good initial estimates on the voltages (not a flat start) took 7 iterations and 63 iterations respectively. The largest change in the a_k's was 0.0013.

Table 5.3. ARC GAIN FACTORS

Arc	Gain Load Flow	Gain OPF	Arc	Gain Load Flow	Gain OPF
1	1.000	1.000	24	.9997	.9995
2	.9973	9972	25	.9968	.9965
3	.9990	.9989	26	.9989	.9977
4	9976	.9974	27	.9932	.9911
5	.9992	9992	28	.9976	9971
6	.9985	9984	29	1.000	1.000
7	.9974	.9973	30	1.000	1.000
8	.9952	9928	31	9991	9977
9	9977	9973	32	.9985	9988
10	9954	.9125	33	9951	9947
11	9950	9961	34	.9955	9947
12	9996	9997	35	9954	9949
13	9951	9957	36	9996	9996
14	9820	9808	37	1.000	1.000
15	1.000	1.000	38	.9933	9927
16	9997	9998	39	.9975	9972
17	9997	9999	40	9985	9982
18	9986	9984	41	9969	9967
19	9988	9987	42	9964	9970
20	1.000	1.000	43	9944	9971
21	9863	9491	44	9900	9936
22	9944	9855	45	9955	9965
23	9974	9973	46	9937	9948

Therefore, not that much more is gained by having tighter convergence criteria.

Also of interest is the information and sensitivity analysis obtained from the dual variables (π_i) at each node as calculated by the GNFP code. At generator #31, the solution showed that it should produce at its minimum requirement, 100 MW. At this node, the GNFP code calculated a π value of -8.18. This means that it would cost $8180 if that minimum requirement were 1 MW greater or 101 MW. So, sensitivity analysis can also be conducted in the framework of the GNFP.

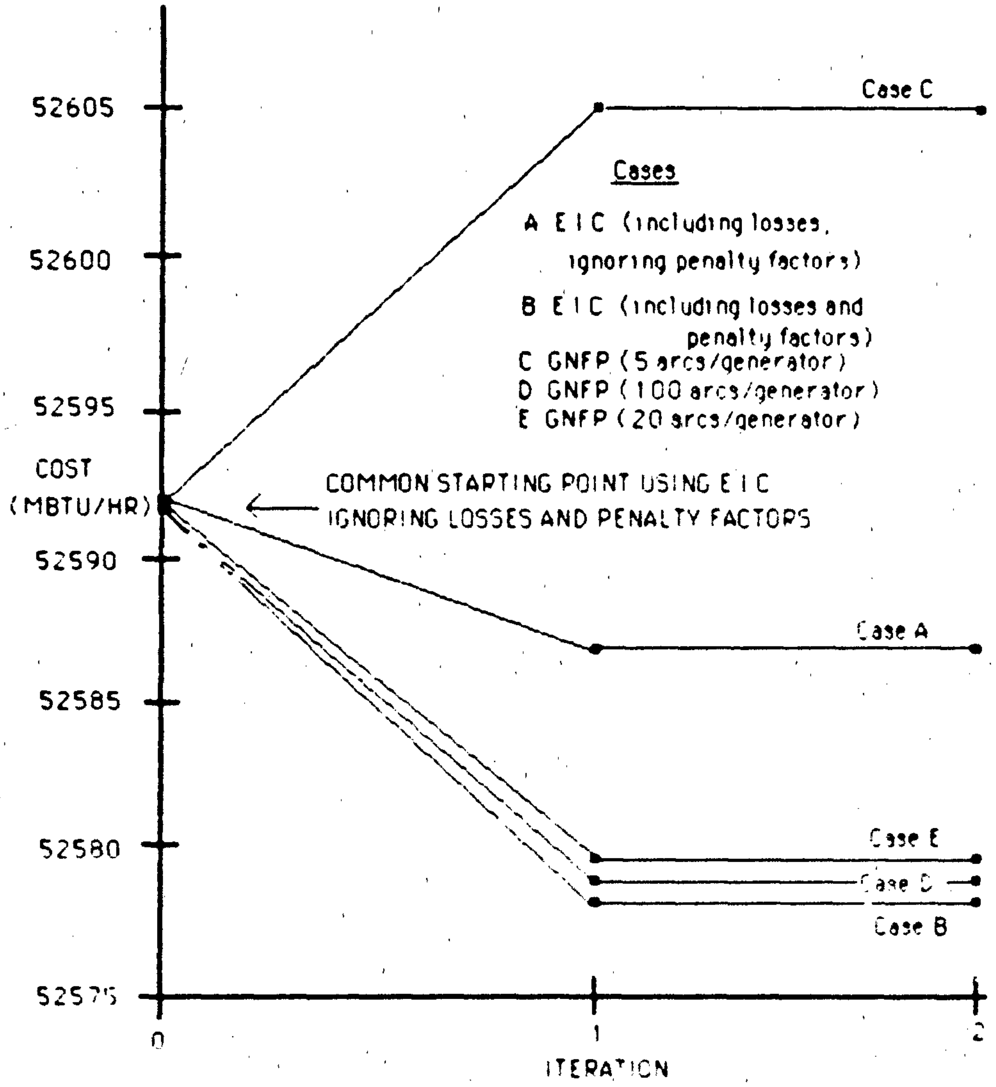
5.1.3 Comparative Example

The purpose of this example is to illustrate the use of GNFP scheduling and to provide the following information: a) a comparison between equal incremental cost dispatch, equal incremental cost dispatch with penalty factors, and GNFP dispatch; b) an evaluation of the number arcs needed for each generating unit; c) a determination of the impact of zero arc flows using GNFP; and d) a demonstration of GNFP scheduling with area generation constraints. Generator cost

functions are in the form of heat rate data for actual units of like size. This data, provided by Houston Lighting & Power Company, is shown in Appendix 5.

Steps a and b are performed simultaneously. Initially, a very careful equal incremental cost dispatch (E.I.C.) schedule without penalty factors is found. This is accomplished as follows - perform E.I.C. excluding losses (this is termed the starting point in Figure 5.2), solve a load flow program to update the swing bus generation, re-solve the E.I.C. with new losses, re-solve the load flow, etc. The last two steps are repeated until the difference between the E.I.C. swing bus power and the load flow swing bus power is less than ±0.001 MW. The results, shown in Figure 5.2 (Case A) and in Table 5.4 indicate that there is no significant change in total generation cost after the first iteration.

Next, the same process is performed using penalty factors. In this example, the penalty factors are evaluated using the method of finite differences as follows - all loads are increased by 1% from Figure 5.2, Case A, generator i is designated as the swing bus, and the corresponding penalty factor is approximated by



*Note Each point shown satisfies Load Flow Mismatch Equations

Figure 5.2 Operating Cost vs iteration for the 39 Bus System using Equal Incremental Cost (E I C) and GNFP Methods

Table 5.4. Generation Schedule (MW) for 39 Bus System
(From Selected Cases shown in Figure 5.2)

BUS	E.I.C STARTING POINT	FINAL E.I.C. w/o PENALTY FACTORS	FINAL E.I.C. with PENALTY FACTORS	GNFP with 20 ARCS/ GENERATOR
31	421.66	426.10	441.00	428.60
32	587.61	550.81	563.37	568.45
33	677.17	688.86	737.02	720.90
34	536.19	542.03	533.67	542.80
35	504.32	507.53	504.00	500.70
36	569.86	572.57	575.57	579.90
37	585.23	588.73	584.60	578.50
38	536.89	538.57	526.26	522.30
39	797.27	801.63	748.97	773.00
System Losses	38.50	39.15	36.76	37.45
Cost (MBTU/HR)	52592	52587	52577	52579

Table 5.5 Penalty Factors for the 39 Bus System

BUS	PENALTY FACTOR
31	0.99972
32	0.99538
33	1.00356
34	1.01760
35	1.01675
36	1.01112
37	1.01696
38	1.03275
39	1.04551

$$pf_i = \frac{1}{1 - \Delta L/\Delta P_i}$$

The results are shown in Table 5.5. (Note - the author does not propose that this method for finding penalty factors be used on large systems since more efficient techniques are available [35]) The results of E.I.C. with penalty factors are shown in Figure 5.2 (Case B) and in Table 5.4. The net reduction in cost from Case A is 10 MBTU/HR

The required number of arcs per generator for the GNFP method is also established in Figure 5.2. Each generator arc, as illustrated in Figure 4.4 represents a segment of the piecewise-linear incremental cost curve. Theoretically, as the number of arcs increases, the accuracy of the GNFP method also increases - but at the expense of computer execution time (approximately linear function of number of arcs plus busses). Note in Figure 5.2, Case C, that 5 arcs/generator yields completely unsatisfactory results, while Case D, with 100 arcs/generator, produces a total cost within 1 MBTU/HR of Case B (E.I.C. with penalty factors). Next, Case E, with 20 arcs/generator, yields results within 2 MBTU/HR of Case B. The conclusion from these

comparisons is that 20 arcs/generator modeling is probably a good compromise between accuracy and execution time.

A comparison of some of the generation scheduling for Figure 5.2 is shown in Table 5.4. Note that *none* of the GNFP procedure schedules required more than one iteration of Figure 4.2 to converge.

<u>Step c</u> is best evaluated through examples. As noted previously, the GNFP method assigns power flow based on arc costs and gains, and it ignores Kirchhoff's Voltage Law. As a result, some arcs are assigned zero flow and some are assigned very large flows, which, of course, is not representative of an actual system. The number of these, however, is reduced greatly by incorporating reasonable line flow limits.

The 39 bus system data does not contain line rating limits. Hence, unlimited values of 99999 MW were used as a reference (indicated as NO LIMIT in Table 5.6). These are compared to the actual flows from the load flow step. Note that 8 of 36 lines were assigned zero flow. Next the GNFP case was re-solved using upper flow limits equal to 1.5 times load flow calculated flow values (indicated as UPPER LIMIT). This reduced the number of zero-flow lines to 3, all of which

Table 5.6. Line Flow Comparisons Between Load Flow Results and GNFP Predictions for the 39 Bus System

LINE FLOWS (MW)

BUS FROM	TO	LOAD FLOW	GNFP NO LIMIT	GNFP UPPER LIMIT	GNFP UP. LIMIT + LOW. LIMIT
1	30	40	154	57	57
2	1	139	254	156	156
2	3	460	324	422	433
3	4	51	0	0	26
3	18	85	0	97	83
5	4	195	501	292	292
5	8	305	0	196	196
6	5	500	501	489	489
6	7	419	611	512	512
7	8	184	375	276	276
9	8	34	148	51	51
10	11	366	555	445	445
10	13	355	166	276	276
11	6	361	555	443	443
11	12	4	0	1	2
13	12	4	8	7	6
13	14	350	157	269	269
14	4	255	0	209	283
14	15	94	157	69	85
16	15	223	164	261	236
16	17	95	158	61	87
17	18	73	158	61	76
17	27	22	0	0	11
19	16	359	359	359	359
19	20	182	182	182	182
21	16	284	295	295	290
22	21	561	572	572	566
22	23	19	9	9	14
23	24	322	311	311	316
24	16	11	0	0	5
25	2	173	160	160	162
26	27	260	282	282	271
28	26	114	277	171	171
29	26	164	0	107	107
29	28	321	485	378	378
30	9	40	154	57	57

Note: Upper Limits Equal 1.50 times Figure 5.2, Case A, flow value
Lower Limits Equal 0.50 times Figure 5.2, Case A, flow value

had low actual flow values. Note that the UPPER LIMIT case produced GNFP flows which are much closer to the load flow calculated flows than those from the NO LIMIT case.

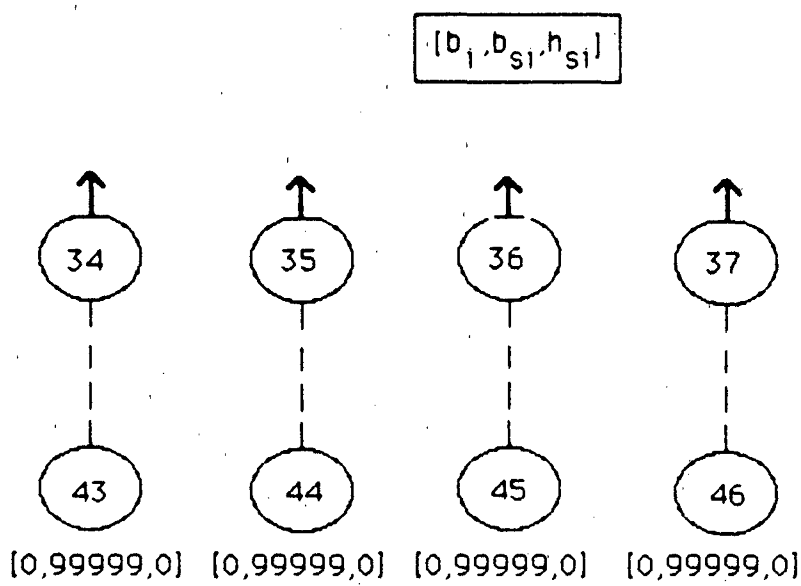
Finally, lower limits of 0.50 times nominal were included in addition to the upper limits. While this eliminated the zero flow problem, it did not have a significant impact on other GNFP flows.

There is *no* net impact of flow limits on the final GNFP generation schedule or total generation cost for the 39 bus example. Therefore, the author concludes that upper bounds on flow limits should be set to line rating values in order to obtain more realistic flows, especially in radial situations. This will also reduce the number of lines with zero flows. The net impact of zero flow arcs on the generation schedule is probably minimal. It should be noted that inclusion of upper flow limits on the arcs actually decreases execution time slightly since, when the maximum flow is obtained in a GNFP step, the corresponding line is excluded as a candidate for additional flow.

<u>Step d</u> is used to demonstrate area generation control capabilities of the GNFP procedure shown in Figure 4.2. For example, assume that the total generation from units 34, 35, 36, and 37 is

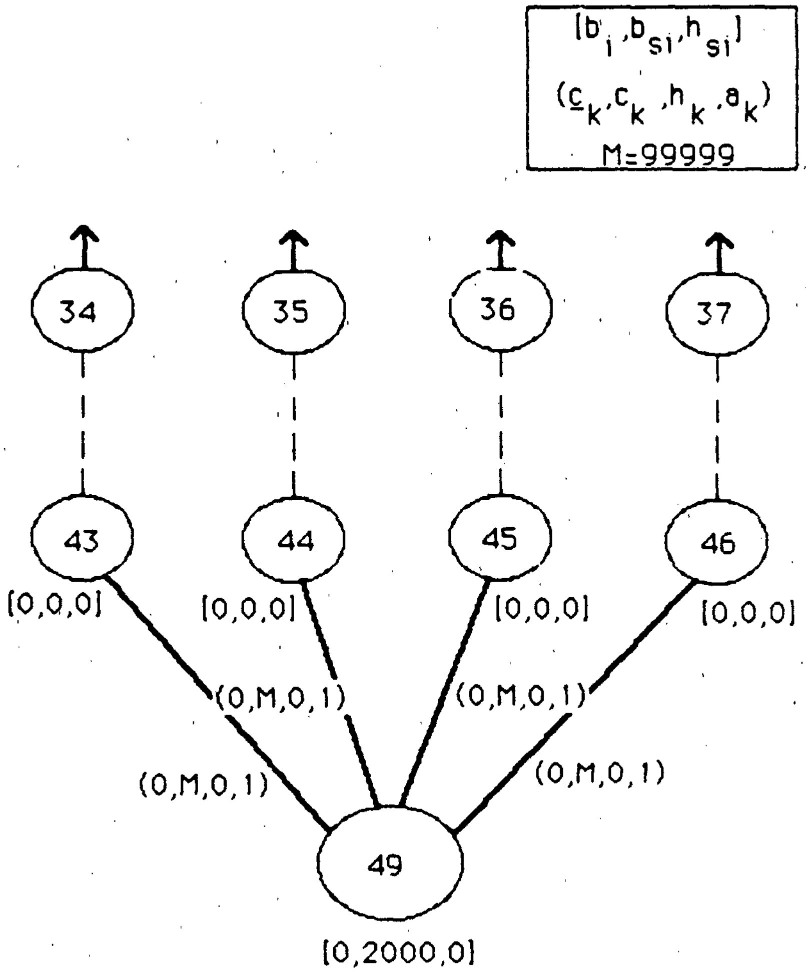
limited to 2000 MW. This constraint is handled very easily by GNFP as follows. First, consider the previous steps a - c. In these cases, the units were modeled independently as shown in Figure 5.3, where each dashed line corresponds to the 20 arcs that are the piecewise-linear incremental cost curve. These 20 arcs contain both the cost data and the bounds of P_{min} and P_{max}. Now, to incorporate area constraint, busses 43 - 46 are attached to new bus number 49, as shown in Figure 5.4, which has a total generation limit of 2000 MW and no cost. The dashed arcs remain unchanged. The GNFP procedure automatically limits the sum of the four generators to not exceed 2000 MW. Likewise, lower limits on generation (other than lower limits from the heat rate data) can also be specified, thereby bounding the generation. Note that since the generators need not be adjacent, this provides a convenient, method to incorporate area security generation requirements while determining the constrained optimal economic dispatch schedule.

This case was solved, yielding a new area generation of 2000 MW and total generation cost of 52677 MBTU/HR. As expected, the constrained case results in higher cost. Only one pass through the GNFP



*Note: - - - is Abbreviation for 20 Arcs

Figure 5.3 GNFP Representation of Generators 34, 35, 36, 37 in the 39 Bus System



*Note - - - is Abbreviation for 20 Arcs

Figure 5.4 GNFP Method to Limit the Sum of Generators 34, 35, 36, 37 to 2000 MW in the 39 Bus System

procedure shown in Figure 4.2 was required.

These examples using the 39 bus system demonstrate the usefulness of the GNFP procedure and are the basis for the following conclusions

- 20 arcs/generator is sufficient modeling detail
- Upper bounds equal to line ratings should be included
- "One pass" through the algorithm in Figure 4.2 is adequate for small systems.

5.2. 376 Bus System

5.2.1. System Description

This case represents the Houston Lighting & Power Company (HL&P) system with reduced equivalents for external systems. The HL&P network is characterized as being compact and electically tight, with relatively low loss. This case contains a total of 376 busses, 870 lines and transformers, 45 generator units "on line" in the HL&P area and connected to 20 generator busses, 12 external areas with generators and loads, and 9 tie lines to HL&P. Total HL&P area generation is approximately 11,500 MW. This system was selected

since it represents a realistic case to test the GNFP solution technique for the OPF.

The data from HL&P is the Load Flow solution in IEEE Standard Format for Load Flow Data. It was input into a program (see Appendix 3) that converts it into the format necessary to serve as input into another code (see Appendix 4) that calculates the gain parameters.

The code at Appendix 4 that calculates the gain parameters was expanded to do an extra task. Besides calculating the arc gains according to Equation 4.10, it creates GNFP node data (node number, fixed external flow, slack flow, slack cost) and arc data (from node, to node, lower bound, capacity, cost, gain) in the sense it was discussed in Chapter I. Thus, this code acts as a network generator for the GNFP codes of Jensen and Barnes.

5.2.2. Area Interchange

As stated earlier, area interchange involves several interconnected powers systems and the load flow solution must satisfy a specified net power interchange for each system. The area

interchange data is also provided in the Load Flow data from HL&P. When solving the load flow for such a system, the first step is to compute the voltages for each bus, with an assumed generation schedule for each system. Next, using these voltages, the power flow on the tie lines are calculated and algebraically summed by system to determine the actual net power interchanges. Finally, the actual and scheduled power interchanges for each system are compared to determine the necessary adjustments in the assumed generation schedules. This often involves a few iterations of the load flow solution to make the necessary adjustments. This load flow data from HL&P represents the solution with area interchange included.

This research uses the following approach to area interchange. First, the power flow on the tie lines into and from the primary power system are held constant when solving the GNFP problem. Then the load flow problem (with area interchange) is resolved with the optimal generation schedule. This approach is necessary to hold the net flow into/out of the system constant. If additional load flows are needed in the iterative loop (Figure 4.2), this process is repeated with the most recent tie line flows.

5.2.3. Load Flow

The HL&P solution shows the real power generation at the swing bus (#546) to be 864.1 MW. As a point of interest, the bus voltages from this solution and the branch impedances (or admittances) were used to calculate the arc gains. With all the busses' real power loads and generations as external fixed flows, zero slack flow, and zero slack costs and with all the arc flow lower bounds equal to zero, capacities set to a very large number, zero arc costs, and the computed arc gains, the GNFP codes were exercised just to see if the real power generation at the swing bus was comparable to the HL&P solution. This is merely solving the load flow equations (without an objective function) with GNFP. The GNFP result was 857.2 MW; off by only .799%. This is strong evidence that the linearization of the problem and the solution with the GNFP codes is very accurate. The execution time on the GNFP solution was approximately 4 seconds.

5.2.4. Optimal Power Flow

HL&P provided generator cost information in the form of

piecewise-linear incremental heat rate segments. Data were available for all HL&P area generator units except for three co-generators. These three units (#181, #182, and #194) were assigned fixed generator active power and were not otherwise considered in the OPF. Cost data for the HL&P owned units were in the form of four piecewise-linear incremental cost segments. The four segments were further divided into 20 segments for the GNFP step, producing 20 arcs for each generating unit. Since the solution time of the GNFP problem is a linear function of the number of nodes and arcs, this linearization of the cost function increased the size of the problem by 50%. Consequently, the solution time increased proportionally. Initial estimates for generator powers, P-V bus voltage magnitudes, and transformer tap settings were obtained from a "base case" load flow solution which represents typical operating conditions. Since the objective of this problem was to minimize generation cost in the HL&P area, generation cost in external areas was not considered.

Using the "base case" load flow solution, the active power gains, a_k, were calculated for all transmission lines/transformers in HL&P. These values range from 0.9734 to 1.000. While, of course,

these gains are actually nonlinear and vary with the square of current, they remain reasonably constant if the solution procedure begins with a well-conditioned initial generation profile. Since the load flow solutions for this network resulted in no constraint violations, iterations were unnecessary.

The resulting generation schedule from the GNFP solution is shown in Table 5.7 along with that schedule obtained by careful application of the equal incremental cost rate method. The GNFP results in a cost savings of less than 1%. This result is not surprising since the HL&P system has relatively low loss and does not have significant remote generation to cause large variations in penalty factors. But the significance lies in the fact that the incremental cost rate method is a "first cut" approach to economic dispatch and does not take into account location of generators and loads and ignores system constraints. The GNFP technique does.

The solution time for the GNFP segment of this problem was 14.2 seconds on a Cyber 170/750. This was with no limits on line flow. Next, the line ratings were enforced and the problem re-solved. Only slight changes in the generation schedule occurred and the solution

Table 5.7. ACTIVE POWER GENERATION SCHEDULE

	Active Power Generation		
		Incremental	
Bus #	Load Flow	Heat Rate	GNFP
53	239.80	310	312.43
55	393.76	460	460.00
111	1307.12	1188	1160.34
112	749.00	747	739.13
176	156.78	139	145.06
181	29.44	29.44	29.44
182	166.81	166.81	166.81
194	950.00	950.00	950.00
274	48.60	46	46.60
275	97.91	80	92.83
276	360.00	324	324.00
278	263.61	271	270.74
487	1531.80	1689	1684.58
488	1697.00	1391	1392.94
546	1317.51	1311	1311.00
547	889.50	882	882.00
726	205.91	428	428.54
735	18.30	17	16.90
736	706.50	699	698.82
737	348.00	348	348.00
Total MW	11,477.35	11,476.25	11,460.15

time was cut to 12.5 seconds. This was due to the fact that fewer iterations were needed in the changes of bases.

CHAPTER VI

CONCLUSIONS, RECOMMENDATIONS, AND EXTENSIONS

6.1. Conclusions

The Optimal Power Flow problem is important in both system planning and operating environments. Due to the complexity in implementation and extensive execution times of existing OPF computer programs, there exists the need for a faster, simpler solution technique which provides reasonable accuracy for system control centers or other environments where speed is critical. A formulation of this type is available through the use of Generalized Network Flow Programming (GNFP).

The methodology for applying GNFP to the OPF problem has been developed and demonstrated in this dissertation using three examples - a simple 5 bus system, a 39 bus system, and an actual 376 bus equivalent system which includes Houston Lighting & Power (HL&P) Company. An equivalent system is one in which the areas

outside the primary system are represented by smaller networks. For example, the 12 outside areas in the HL&P data actually contain over 1000 busses. But, through the manipulation of impedances, they can be reduced to a few hundred. Based on the development of the GNFP method and its subsequent results, ~~the following~~ conclusions can be made.

Solution time for the GNFP segment of the HL&P problem was 12.5 seconds on a Cyber 170/750. For larger systems, the execution time increases linearly with the number of lines plus busses in a network, based on previous studies by Jensen and Barnes [1].

Salient features of the GNFP method include the ability to minimize generation cost while meeting system constraints such as line flow limits. As shown in Section 5.1.3, network location of loads and generators is considered in GNFP without need of penalty factors which are necessary in methods of equal incremental costs.

Power flow constraints on transmission lines do not affect GNFP solution time significantly. Area generation security constraints, in addition to conventional area interchange

requirements, can be included by placing appropriate flow limits on interconnecting transmission lines. Area interchange and reactive power generation limits are considered in the companion power flow solution.

The GNFP solution technique is a linear approximation to a nonlinear problem. By the theorem of complementary slackness, it's solution is optimal [1]. How closely the GNFP results agree with the results from other established methods has not yet been determined. This can be found only by comparing the results of many cases to those obtained by some of the commercially available OPF solution methods. However, this author estimates that, with adequate modeling of the generation cost functions (i.e., 20 arcs/generator as shown in Section 5.1.3), the GNFP solution is within 2-5% of the actual solution achieved by nonlinear techniques.

6.2. Recommendations

The author recommends that research efforts be undertaken to determined how the results of this new method compare to other well-accepted techniques. This can only be done by extensive

comparisons on several example systems. This will require the cooperation of another agency or firm that has ready access to these exact methods. Along these same lines, this author strongly recommends that the Electrical Engineering Department at the University of Texas purchase or develop a state of the art Load Flow computer code capable of handling large, real-world power systems. The present capability is inadequate.

There are also tremendous opportunities for more research into the application of Generalized Network Flow Programming in other areas dealing with power distribution. Some of the areas for follow-on research and extensions are discussed in the following section.

6.3. Extensions

Some areas where GNFP could be applied are fuel scheduling and contingency analysis [11]. A form of network programming has been attempted on these problems, but not of the type with gain factors.

Area security, area interchange, fault analysis and unit

committment are some smaller areas of research that show promise in future studies. Their study would not necessarily require enormous effort.

Long range strategic planning can also benefit from the application of GNFP. The acquisition and addition of new generating plants or the location of new customers has considerable economic and engineering impact on a power system. Judicious application of GNFP techniques could be a valuable tool in evaluating these impacts.

Another area of interest is the physical and mathematical interpretation of the dual variables, π_i, at optimality. They represent the cost of getting one more unit to the respective node. Since the π_i's are a function of the a_k's, the losses in the system are considered. This author submits that the π_i's and the penalty factors, λ_i, discussed in Chapter V, have a close relationship. This area should be examined.

As mentioned in Step 10 in Section 4.2, the procedure to modify generator voltages, transformer taps, and/or capacitor banks to relieve constraint violations is not mechanized at this time.

Adjustments may call for voltages to be fixed at certain values, or Q injections/extractions, or some other measure deemed necessary. The mechanization of this procedure is a logical next step.

This author sees, however, that there is an extremely important and immediate problem in the power industry: Reactive Power Dispatch. A particular IEEE Committee Report [12] focuses attention on the var management control problems being experienced in the power industry. The conclucion of this report is, "Var flow and its effect on voltage profile have a significant impact on power system operation. Var management will almost certainly be recognized as an increasingly important factor in energy control."

With the development, in Chapter IV, of the gain parameter, a'_K, for reactive power flow, the solution of optir .eactive power dispatch is a logical next step. No objective function is required: only the solution of the reactive mismatch equations. The primary difficulties to overcome would be the handling of line charging and shunt MVars. Minimum Q dispatch will involve the Q generations and transformer taps to keep voltages within limits. Once this is accomplished, techniques to combine the two (MW and MVar) dispatch

problems would be necessary.

This author has already begun research in this area and the results should be ready for publication soon.

APPENDIX 1: LOAD FLOW AND ARC GAINS - 5 BUS

```
      PROGRAM GAIN(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)
      COMPLEX V1,V2,YP,Y,X1,X2,Y1,Y2,LOSS,T,S,VI,SI,SUM,VN,VO
      DIMENSION YP(5,5),Y(5,5),VI(5),SI(5),KV(3),PVMAG(3),VN(5),VO(5)
      SUM=(0.0,0.0)
      ALPHA=1.4
C     READ IN NUMBER OF BUSES
      READ(5,*)N
C     READ IN VOLTAGE ESTIMATES
      DO 5 I=1,N
      READ(5,10)VI(I)
 10   FORMAT(1X,F7.5,1X,F7.5)
      VO(I)=VI(I)
 5    CONTINUE
C     READ IN POWER REQUIREMENTS (IN PER UNIT)
      DO 15 I=2,N
      READ(5,20)SI(I)
      SI(I)=CONJG(SI(I))
 20   FORMAT(1X,F5.2,1X,F5.2)
 15   CONTINUE
C     READ * OF P-V BUSES AND MAGNITUDES
      READ(5,*)NPV
      IF(NPV.EQ.0) GO TO 50
      DO 25 I=1,NPV
      READ(5,30)KV(I),PVMAG(I)
 30   FORMAT(1X,I2,1X,F5.3)
 25   CONTINUE
C     ZERO OUT ADMITTANCE MTX
 50   DO 52 I=1,N
      DO 51 J=1,N
 51   Y(I,J)=(0.0,0.0)
 52   CONTINUE
C     READ IN * OF BRANCHES OR ARCS
      READ(5,*)NA
C     READ BEGIN NODE, END NODE, ADMITTANCE MTX ELEMENT, AND
```

```
C     0.5*TOTAL LINE CHARGING ADMITTANCE
      DO 75 I=1,NA
 75   READ(5,85)K,L,Y(K,L),YP(K,L)
 85   FORMAT(1X,I2,1X,I2,4(1X,F9.5))
C     READ IN THE DIAGONAL ELEMENTS OF THE ADMITTANCE MTX
      DO 78 I=1,N
 78   READ(5,79)Y(I,I)
 79   FORMAT(1X,F8.5,1X,F9.5)
      DO 74 I=1,N
      DO 73 J=1,N
      Y(J,I)=Y(I,J)
      YP(J,I)=YP(I,J)
 73   CONTINUE
 74   CONTINUE
C     GO TO 60
      DO 64 II=1,10
      DO 60 I=2,N
      DO 68 J=1,N
      IF (I.EQ.J) GO TO 68
      SUM=SUM+Y(I,J)*VI(J)
      IF (I.EQ.KV(J) GO TO 69
 68   CONTINUE
      VI(I)=(1/Y(I,I))*(SI(I)/(CONJG(VI)I)))-SUM)
 69   SUM=(0.0,0.0)
      VN(I)=VO(I)+ALPHA*(VI(I)-VO(I))
C     ADJUSTING MAGNITUDES OF P-V BUSES
      DO 80 J=1,NPV
      IF(I.NE.KV(J)) GO TO 80
      VN(I)=VN(I)*PVMAG(J)/CABS(VN(I))
 80   CONTINUE
      VI(I)=VN(I)
      VO(I)=VN(I)
 60   CONTINUE
 64   CONTINUE
      WRITE(6,90)
 90   FORMAT(1X,20HPOWER FLOW AND GAINS)
      PRINT*,
      DO 100 I=1,N-1
      DO 125 J=I+1,N
```

```
      IF(Y(I,J).EQ.(0.0,0.0)) GO TO 125
      V1=VI(I)
      V2=VI(J)
      X1=CONJG(V1)*(V1-V2)*Y(I,J)*(-1.0)
      Y1=CONJG(V1)*V1*YP(I,J)
      X2=CONJG(V2)*(V2-V1)*Y(I,J)*(-1.0)
      Y2=CONJG(V2)*V2*YP(I,J)
      LOSS=X1+Y1+X2+Y2
      T=X1+Y1
      S=X2+Y2
      IPF=I
      IPT=J
      IQF=I
      IQT=J
      PL=REAL(LOSS)/REAL(T)
      IF(REAL(T).GT.0.0) GO TO 150
      PL=REAL(LOSS)/REAL(S)
      IPF=J
      IPT=I
150   QL=AIMAG(LOSS)/AIMAG(T)
      IF(AIMAG(T).LT.0.0) GO TO 151
      QL=AIMAG(LOSS)/AIMAG(S)
      IQF=J
      IQT=I
151   RGAIN=1-PL
      QGAIN=1-QL
      WRITE(6,175)IPF,IPT,RGAIN
175   FORMAT(5X,21H REAL POWER FLOW FROM, I2,4H TO ,I2,1X,F6.4)
      WRITE(6,176)IQF,IQT,QGAIN
176   FORMAT(1X,25HREACTIVE POWER FLOW FROM ,I2,4H TO ,I2,1X,F6.4)
125   CONTINUE
100   CONTINUE
      PRINT*,
      END
```

APPENDIX 2: LOAD FLOW AND ARC GAINS - 39 BUS

```
      PROGRAM GAIN(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)
      COMPLEX V1,V2,YP,Y,X1,X2,Y1,Y2,LOSS,T,S,VI,SI,SUM,VN,VO,
     1TOT,SS,TT,LOSS1,PSUM
      DIMENSION YP(39,39),Y(39,39),VI(39),SI(39),KV(8),PVMAG(8),
     1VN(39),VO(39),PVPWR(8)
      MAXIT=200
      TOT=(0.0,0.0)
      SUM(0.0,0.0)
      ALPHA=1.4
C     READ IN NUMBER OF BUSES
      READ(5,*) N
C     READ IN VOLTAGE ESTIMATES
      DO 5 I=1,N
      READ(5,10)VI(I)
   10 FORMAT(1X,F7.5,1X,F7.5)
      VO(I)=VI(I)
    5 CONTINUE
C     READ IN POWER REQUIREMENTS (IN PER UNIT)
      DO 15 I=2,N
      READ(5,20)SI(I)
      SI(I)=CONJG(SI(I))
   20 FORMAT(1X,F7.4,1X,F7.4)
   15 CONTINUE
C     READ * OF P-V BUSES AND MAGNITUDES
      READ(5,*)NPV
      IF(NPV.EQ.0) GO TO 50
      DO 25 I=1,NPV
      READ(5,30)KV(I),PVMAG(I)
   30 FORMAT(1X,I2,1X,F5.3)
   25 CONTINUE
C     ZERO OUT ADMITTANCE MTX
   50 DO 52 I=1,N
      DO 51 J=1,N
      YP(I,J)=(0.0,0.0)
   51 Y(I,J)=(0.0,0.0)
   52 CONTINUE
C     READ IN * OF BRANCHES OR ARCS
      READ(5,*)NA
```

```
C     READ BEGIN NODE, END NODE, IMPEDANCE MTX ELEMENT, AND
C     0.5*TOTAL LINE CHARGING IMPEDANCE
      DO 75 I=1,NA
 75   READ(5,85)K,L,Y(K,L),YP(K,L)
 85   FORMAT(1X,I2,1X,I2,1X,F4.2,1X,F4.2,1X,F4.2,1X,F6.2)
C     CONVERT IMPEDANCE TO ADMITTANCES AND LINE CHARGING
      DO 74 I=1,N
      DO 73 J=1,N
      IF(CABS(Y(I,J)).EQ.0.0) GO TO 73
      Y(I,J)=-100.0/Y(I,J)
      IF(CABS(YP(I,J)).NE.0.0) GO TO 70
      YP(I,J)=(0.0,0.0)
      GO TO 71
 70   YP(I,J)=YP(I,J)/200.0
C     I DID THIS TO GET YP/2
 71   Y(J,I)=Y(I,J)
      YP(J,I)=YP(I,J)
 73   CONTINUE
 74   CONTINUE
C     CALCULATE DIAGONAL ELEMENTS OF ADMITTANCE MTX
      DO 78 I=1,N
      DO 79 J=1,N
      IF(I.EQ.J) GO TO 79
      TOT=TOT-(Y(I,J)-YP(I,J))
 79   CONTINUE
      Y(I,I)=TOT
      TOT=(0.0,0.0)
 78   CONTINUE
C     NOW READ IN THE NUMBER OF TRANSFORMERS AND THE TAP RATIOS
      READ(5,*)NT
      IF(NT.EQ.0.0) GO TO 95
      DO 95 K=1,NT
      READ(5,96)I,J,TAPRAT
 96   FORMAT(1X,I2,1X,I2,1X,F5.3)
C     ADJUST ADMITTANCE MATRIX DIAGONAL ELEMENTS
C     YP MATRIX ELEMENT WILL BE USED TO ADJUST FLOW IN GAIN CALCS
      Y(I,I)=Y(I,I)+Y(I,J)-Y(I,J)/(TAPRAT)**2
      YP(I,J)=(Y(I,J)/TAPRAT)*(1.0/TAPRAT-1.0)*(-1.0)
      YP(J,I)=YP(I,J)*TAPRAT*(-1.0)
```

```
      Y(I,J)=Y(I,J)/TAPRAT
      Y(J,I)=Y(I,J)
   95 CONTINUE
C     READ NUMBER OF NODES WITH SHUNT MEGAVARS
      READ(5,*)NSHUNT
C     READ IN NODE AND SHUNT MVAR/100 (- FOR CAP,+ FOR RES)
      IF(NSHUNT.EQ.0) GO TO 99
      DO 99 I+1,NSHUNT
      READ(5,98)K,SHNTMV
   98 FORMAT(1X,I3,1X,F6.3)
      A=0.0
      Y(K,K)=Y(K,K)-CMPLX(A,SHNTMV)
   99 CONTINUE
      DO 64 II=1,MAXIT
      NFLAG=0
      DO 60 I=2,N
      IFLAG=0
      DO 68 J=1,N
      IF(I.EQ.J) GO TO 68
      SUM=SUM+Y(I,J)*VI(J)
      IF(I.NE.KV(J)) GO TO 68
      IFLAG=J
   68 CONTINUE
      IF(IFLAG.EQ.0) GO TO 69
      PSUM=SUM+Y(I,I)*VI(I)
      PT=AIMAG(CONJG(VI(I))+PSUM)
      PWR=REAL(SI(I))
      SI(I)=CMPLX(PWR,PT)
   69 VI(I)=(1.0/Y(I,I))*(SI(I)/(CONJG(VI(I)))-SUM)
      SUM=(0.0,0.0)
      PSUM=(0.0,0.0)
      IF(IFLAG.NE.0) GO TO 67
      VN(I)=VO(I)+ALPHA*(VI(I)-VO(I))
      IF(CABS(VN(I)-VO(I)).GT.0.001)NFLAG=1
C     ADJUSTING MAGNITUDES OF P-V BUSES
      IF(IFLAG.EQ.0) GO TO 81
   67 VN(I)=VI(I)*PVMAG(IFLAG)/CABS(VI(I))
   80 CONTINUE
   81 VI(I)=VN(I)
```

```
      VO(I)=VN(I)
60    CONTINUE
      NUMIT=II
      IF(NFLAG.EQ.0) II=MAXIT
64    CONTINUE
      WRITE(6,90)
90    FORMAT(7X,20HPOWER FLOW AND GAINS)
      PRINT*,
      DO 100 I=Q,N-1
      IFLAG=0
      DO 102 KK=1,NPA
      IPV=I+1
      IF(IPV.NE.KV(KK)) GO TO 102
      IFLAG=KK
103   WRITE(6,104)IPV,CONJG(SI(IPV))
104   FORMAT(1X,12HPOWER AT BUS,I3,4H IS ,2(F9.4,1X))
102   CONTINUE
      DO 125 J=I+1,N
      IF(CABS(Y(I,J)).EQ.0.0) GO TO 125
      V1=VI(I)
      V2=VI(J)
      X1=CONJG(V1)*(V1-V2)*Y(I,J)*(-1)
      Y1=CONJG(V1)*V1*YP(I,J)
      X2=CONJG(V2)*(V2-V1)*Y(I,J)*(-1)
      Y2=CONJG(V2)*V2*YP(J,I)
      LOSS1=X1+X2
      TT=X1
      SS=X2
      LOSS=X1+Y1+X2+Y2
      T=X  +Y1
      S=X2+Y2
      IPF=I
      IPT=J
      PL=REAL(LOSS)/REAL(T)
      IF(REAL(T).GT.0.0) GO TO 151
      PL=REAL(LOSS)/REAL(S)
      IPF=J
      IPT=I
151   RGAIN=1-PL
```

```
      WRITE(6,175)IPF,IPT,RGAIN
175   FORMAT(5X,26HREAL POWER FLOW GAIN FROM,I2,4H TO ,I2,1X,F6.4)
125   CONTINUE
100   CONTINUE
      PRINT*,
      WRITE(6,250)NUMIT
250   FORMAT(1X,5HAFTER,1X,I3,1X,10HITERATIONS)
      END
```

APPENDIX 3: DATA FORMATTING ROUTINE

```
      PROGRAM FOMAT(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)
C     THIS PROGRAM READS LOAD FLOW DATA IN STANDARD IEEE
C     FORMAT AND CONVERTS IT INTO A FORMAT COMPATABLE WITH
C     ROY RICE'S GAINS CODE
C
C     READ NUMBER OF BUSES
      II=0
      READ(5,*)NUMBUS
      WRITE(6,7)NUMBUS
 7    FORMAT(1X,I4)
C     READ BUS DATA
      DO 10 I=1,NUMBUS
      READ(5,20)IBNUM,ANAME,BNAME,IBTYPE,VMAG,ANGLE,PL,QL,PG,QG,
     1DVMAG,SHNTMVR
 20   FORMAT(I4,1X,A6,A6,8X,I1,1X,F6.4,1X,F6.2,2X,F7.2,2X,F7.2,
     12X,F7.2,1X,F7.2,9X,F6.4,26X,F6.4)
      SHNTMVR=100.0*SHNTMVR
      PWR=PG-PL
      ITYPE=IBTYPE
      IF(IBTYPE.EQ.0)ITYPE=3
      IF(IBTYPE.EQ.3)ITYPE=1
      WRITE(6,31)IBNUM,VMAG,ANGLE,PWR
 31   FORMAT(1X,I4,1X,F6.4,1X,F6.2,1X,F7.2)
 10   CONTINUE
C     READ IN NUMBER OF LINES
      READ(5,*)NARC
      WRITE(6,7)NARC
C     READ LINE AND TRANSFORMER DATA
      DO 50 J=1,NARC
      READ(5,60)IFROM,ITO,ITYPE,R,X,CHARGE,TAP
 60   FORMAT(I4,1X,I4,9X,I1,1X,F9.6,1X,F9.6,2X,F8.5,27X,F6.4)
      CHARGE=100.0*CHARGE
      WRITE(6,69)IFROM,ITO,ITYPE,R,X,TAP
 69   FORMAT(1X,I4,1X,I4,1X,I1,1X,F9.6,1X,F9.6,1X,F6.4)
 50   CONTINUE
      END
```

APPENDIX 4: ARC GAINS AND NETWORK GENERATOR

```
      PROGRAM GAIN(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)
      COMPLEX V1,V2,Y,X1,X2,LOSS,VI,SS,TT
      DIMENSION VI(400),B(400),PWR(400)
      II=0
      BB=0.0
      UB=99999
C     READ IN  NUMBER OF BUSES
      READ(5,*)N
      WRITE(6,10)N
 10   FORMAT(1X,I4)
C     READ IN BUS NUMBER AND VOLTAGE ESTIMATES
      DO 5 I=1,N
      READ(5,20)IBNUM,V,A,PWR(I)
 20   FORMAT(1X,I4,1X,F6.4,1X,F6.2,1X,F7.2)
      B(I)=IBNUM
C     CONVERT A (DEGREES) TO RADIANS
      A=A*0.0174533
      XX1=V*COS(A)
      XX2=V*SIN(A)
      VI(I)=CMPLX(XX1,XX2)
      WRITE(6,15)I,PWR(I),BB,BB
 15   FORMAT(I5,3F10.2)
  5   CONTINUE
      WRITE(6,10)II
C     READ IN * OF BRANCHES OR ARCS
      READ(5,*)NA
C     READ FROM BUS, TO BUS, TRANSFORMER TYPE,
C     LINE IMPEDANCE AND TAP RATIO
      WRITE(6,100)
 100  FORMAT(7X,20HPOWER FLOW AND GAINS)
      DO 200 I=1,NA
      READ(5,60)K,L,ITYPE,R,X,,TAPRAT)
 60   FORMAT(1X,I4,1X,I4,1X,I1,1X,F9.6,1X,F9.6,1X,F6.4)
C     CONVERT IMPEDANCES TO ADMITTANCES
      Y=CMPLX(R,X)
      Y=1.0/Y
C
```

```
      IFLAG=0
      DO 50 J=1,N
      IF(B(J).NE.K) GO TO 65
      IFROM=J
      V1=VI(J)
      IFLAG=IFLAG+1
65    IF(B(J).NE.L) GO TO 70
      ITO=J
      V2=VI(J)
      IFLAG=IFLAG+1
70    IF(IFLAG.EQ.2) GO TO 75
50    CONTINUE
75    IF(ITYPE.EQ.0 GO TO 85
      X1=CONJG(V1)*(V1/TAPRAT-V2)*Y/TAPRAT
      X2=CONJG(V2)*(V2-V1/TAPRAT)*Y
      GO TO 90
85    X1=CONJG(V1)*(V1-V2)*Y
      X2=CONJG(V2)*(V2-V1)*Y
90    TT=X1
      SS=X2
      IF(SS.EQ.0.0.AND.TT.EQ.0.0) NGO TO 200
      LOSS=X1+X2
      IPF=IFROM
      IPT=ITO
      PL=REAL(LOSS)/REAL(TT)
      IF(REAL(TT).GT.0.0) GO TO 151
      PL=REAL(LOSS)/REAL(SS)
      IPF=ITO
      IPT=IFROM
151   RGAIN=1-PL
      WRITE(6,176)IPF,IPT,BB,UB,BB,RGAIN
176   FORMAT(2I5,4F10.4)
200   CONTINUE
      END
```

APPENDIX 5: HEAT RATE DATA FOR THE 39 BUS SYSTEM

Bus	Unit	P_{max}	P_{min}	HE_{min}
31	1	441.0	193.6	1992.4
32	1	630.0	274.3	3584.4
33	1	749.0	186.6	2215.8
34	1	750.0	184.7	2095.7
35	1	551.3	214.3	2284.0
36	1	750.0	183.1	2420.8
37	1	747.0	185.5	2066.2
38	1	630.0	270.9	3561.1
39	1	540.0	227.1	2720.1
39	2	527.0	222.2	2555.3

P_{max}, P_{min} : Maximum and Minimum Machine Capabilities - MW

HE_{min} : Minimum Heat Input Required by the Machine When On-Line - MBTU/HR

(X, Y) : Points on the Incremental Heat Rate Curve - (MW, BTU/KWH)

(X1,Y1)		(X2,Y2)		(X3,Y3)		(X4,Y4)		(X5,Y5)	
193.6	8800	255.0	9000	316.5	9250	377.9	9500	441.3	9850
274.3	6550	371.2	7842	470.1	8600	567.0	10000	665.8	11650
186.6	9300	327.6	9350	468.6	9500	609.7	9600	752.7	9900
184.7	8750	325.7	9[illegible]00	466.7	9450	609.7	10050	750.7	10750
214.3	8200	299.6	8500	382.8	8900	466.1	9450	551.3	10100
183.1	7250	324.5	7850	466.0	8800	609.4	10100	750.8	11750
185.5	8400	325.4	8550	465.3	8900	607.1	9895	747.0	9950
270.9	6700	369.5	7550	468.1	8750	568.7	10200	669.3	11950
227.1	7900	313.5	9000	399.8	9947	486.2	11005	574.5	11800
222.2	8000	308.8	8600	395.3	9500	481.8	10500	570.3	11850

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